BEFORE THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA

DOCKET NO. 2019-185-E
DOCKET NO. 2019-186-E

In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	)	**REBUTTAL TESTIMONY OF NICK WINTERMANTEL ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION OF EXPERT WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nick Wintermantel, and my business address is 1935 Hoover Court, Hoover, AL, 35226.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Principal Consultant and Partner at Astrapé Consulting. Astrapé is a consulting firm that provides expertise in resource planning and resource adequacy to utilities across the United States and internationally.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did. I previously filed Direct Testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke") on August 14, 2019.

Q. ARE YOU INCLUDING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. Yes. Wintermantel Rebuttal Exhibit 1 is the pre-filed testimony of North Carolina Utilities Commission—Public Staff ("NC Public Staff") Utilities Engineer Jeff Thomas, as recently filed in North Carolina Utilities Commission ("NCUC") Docket No. E-100, Sub 158 on June 21, 2019. A primary focus of Mr. Thomas' recent testimony in North Carolina was his review of the same Astrapé Ancillary Service Study ("Astrapé Study" or "Study") that I sponsored as Wintermantel Exhibit 2 to my Direct Testimony in this proceeding. I am providing this testimony for the Commission's convenience as my Rebuttal

Testimony references the NC Public Staff's review of the Astrapé Study and determination that Astrapé's modeling, assumptions, and conclusions regarding the increased ancillary service requirements to integrate increasing penetrations of solar into the DEC and DEP systems were reasonable.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony responds to the Direct Testimony submitted by the Office of Regulatory Staff ("ORS") Witness Brian Horii, Southern Alliance for Clean Energy and South Carolina Coastal Conservation League ("SACE/CCL") Witness Brendan Kirby, and South Carolina Solar Business Alliance ("SBA") Witness Ed Burgess concerning the Astrapé Study performed on behalf of the Companies. Specifically, my Rebuttal Testimony first recognizes the areas of agreement among the parties who reviewed the Study. Then I focus on the review and validation of the Study including the recent review by the NC Public Staff. Next I summarize ORS Witness Horii's response and recommendation to approve the Study's charges. I then summarize and rebut the critiques of the Study by SBA Witness Burgess and SACE/CCL Witness Kirby on behalf of the solar industry. These parties present generally consistent critiques of the Astrapé Study in an effort to reduce the increased ancillary services costs assigned to solar QFs. In contrast, the ORS's expert Witness Horii and the NC Public Staff through their recent extensive review of the same Study found the modeling and results of the Study to be reasonable. Finally, I provide additional benchmarking analysis showing that the solar Integration Service Charge ("SISC") of $1.10/MWh proposed by

DEC and the $2.39/MWh SISC proposed by DEP are reasonable and lower than the majority of studies cited including the Dominion Energy South Carolina ("DESC") charge of $3.52/MWh. Finally, in my opinion, Duke has reasonably committed to biennially update the Study to recognize changing resource mixes, intra-hour solar volatility data, load forecasts, gas forecasts, etc., in order to ensure the most accurate incremental ancillary services requirements and SISC are presented to the Commission for approval.

II. OVERVIEW AND AREAS OF AGREEMENT REGARDING THE SOLAR ANCILLARY SERVICE STUDY

Q. PLEASE REINTRODUCE THE GENERAL PURPOSE, PREMISE, METRICS, AND RESULTS OF THE ASTRAPÉ STUDY.

A. The purpose of the Study was to analyze multiple increasing penetrations of installed and projected solar on the DEC and DEP systems to quantify the cost of utilizing DEC's and DEP's existing generating fleets to reliably and cost-effectively integrate the addition of these solar generating resources. As I explain in my Direct Testimony, the Solar Ancillary Service Study utilized Astrapé's proprietary SERVM Model and was based upon the premise that the reliability of the DEC and DEP systems after incremental solar generation is added should remain the same as the reliability of the systems without solar. The Study uses the Loss of Load Expectation flexibility metric ("$LOLE_{FLEX}$") as the primary reliability metric which represents the number of loss of load events due to system flexibility constraints, calculated in events per year. $LOLE_{FLEX}$ is intended to measure the ability of a system to carry enough reserves to follow its net load given 5-minute ahead perfect foresight. As a result of the Study, an average ancillary services cost impact of $1.10/MWh was calculated for DEC and $2.39/MWh was calculated for DEP to integrate the Existing Plus Transition levels of solar generation projected to be installed on the DEC and DEP systems in 2020.

Q. DO THE PARTIES TO THIS PROCEEDING AGREE THAT INCREASED AMOUNTS OF SOLAR ON THE COMPANIES' SYSTEM CAUSES INCREASED NET LOAD VOLATILITY?

A. Yes. I think it is fair to say that each party having provided testimony in this proceeding either affirmatively recognizes or implicitly concedes that the additions of intermittent solar increases net load volatility on the DEC and DEP systems. Duke is also presenting the Rebuttal Testimony of its Vice President of System Planning and Operations, Sam Holeman, to further describe the increased volatility that DEC and especially DEP have experienced as unscheduled and unconstrained QF solar has been added to each utility's system.

Q. DO THE OTHER PARTIES ALSO AGREE THAT INCREASED AMOUNTS OF NET LOAD VOLATILITY ON THE COMPANIES' SYSTEMS CHANGES THE WAY THE DEC AND DEP SYSTEMS TRADITIONALLY OPERATE, RESULTING IN INCREASED SYSTEM COSTS?

A. Yes. It is undisputed that as a result of the increase in net load volatility on the Companies' systems, the systems operate differently and in such a way that results in increased system costs. For example, ORS Witness Horii states that "integrating renewable generation creates additional costs for utilities" and that "E3 has conducted extensive work in California and Hawaii where renewable generation comprises a large portion of the generation resources."[1] SACE/CCL Witness Kirby states that "[t]he basic premise that adding variable renewable generation to the power system may increase operating costs is not unreasonable. The analysis methodology of comparing production cost simulations with and without solar, while adjusting reserves in order to maintain reliability, is also sound."[2]

Q. DO ANY OF THE INTERVENORS DISPUTE THE PREMISE OF THE ANCILLARY SERVICE STUDY THAT THE SAME LEVEL OF RELIABILITY SHOULD BE MAINTAINED BEFORE AND AFTER SOLAR ADDITIONS ARE ADDED AND THAT ADDITIONAL OPERATING RESERVES ARE NEEDED TO MAINTAIN THE PRE-SOLAR RELIABILITY?

A. No. It is my understanding that each of the witnesses who have provided testimony generally agree with the Study's underlying premise that the reliability of the DEC and DEP systems after incremental solar generation is added should remain the same as the reliability of the DEC and DEP systems before solar generation is added. ORS Witness Horii specifically found that "[Astrapé] evaluated additional resources (via increased operating reserves

[1] ORS Horii Direct, at 19.
[2] SACE/CCL Kirby Direct, at 5.

requirements) needed to maintain a specific level of reliability with and without incremental solar resources, as well as the increased operating costs of the generation fleet to respond to solar output intermittency."[3] SACE/CCL Witness Kirby similarly recognizes that "[i]n order to make a fair comparison, it is necessary to hold reliability constant in the no-solar and solar generation cases so that calculated integration costs are not reduced (or increased) as the result of a drop (or increase) in reliability."[4]

III. REVIEW AND VALIDATION OF THE ANCILLARY SERVICE STUDY

Q. SACE/CCL WITNESS KIRBY AND SBA WITNESS BURGESS TAKE ISSUE WITH THE FACT THAT THE STUDY WAS NOT FORMALLY "PEER REVIEWED." PLEASE PROVIDE A SUMMARY OF HOW THE STUDY WAS REVIEWED AND THE STUDY'S RESULTS VALIDATED.

A. The Ancillary Service Study began in the 4th quarter of 2017 and was completed in November 2018. Both Duke and Astrapé experts spent significant time validating the inputs, modeling, and results of the Study. In addition, the Study was reviewed extensively in North Carolina by the NC Public Staff during a recent six month long avoided cost proceeding in North Carolina. While a peer review including additional research and input from academic entities was not conducted, significant time and effort went into reviewing and validating the

[3] ORS Horii Direct, at 19.
[4] SACE/CCK Kirby Direct, Appendix A, at 2.

Study. Witness Snider discusses the peer review and the Companies' stance on the need for a peer review for future studies.

Q. TO YOUR KNOWLEDGE, WERE OTHER SOLAR INTEGRATION STUDIES PRODUCED IN NORTH CAROLINA OR SOUTH CAROLINA PEER REVIEWED?

A. No. Neither the integration study performed by Dominion Energy in North Carolina nor the integration study performed by Dominion Energy South Carolina had a peer review conducted to my knowledge.

Q. PLEASE PROVIDE A DETAILED SUMMARY OF THE NC PUBLIC STAFF'S REVIEW AND CONCLUSIONS REGARDING THE ANCILLARY SERVICE STUDY.

A. As background, the NC Public Staff reviewed the Study extensively and requested additional information in regard to specific aspects of the Study which included some of the same critiques discussed by intervenors in South Carolina. These included (1) modeling DEC and DEP as islands in the Study (2) the limited amount of 5-minute solar volatility data (October 2016 – September 2017), especially in projecting future solar penetration levels; and, (3) the assertion, based on SACE/CCL Witness Kirby's analysis (who also participated in the North Carolina proceeding and generally made the same assertions in that proceeding), that the reliability standard Duke used was too stringent. After several telephone conferences and collaborative meetings between Astrapé, the Companies, and the NC Public Staff, as well as the NC Public Staff's independent investigation of other integration cost studies, the

NC Public Staff was able to validate the reasonableness of the Study, as discussed on pages 3-14 of my Wintermantel Rebuttal Exhibit 1. Further, the NC Public Staff agreed to a Stipulation in support of the Integration Services Charge. Following the collaborative efforts and review, NC Public Staff expert Witness Jeff Thomas testified that the Study was "reasonable" and concluded that "assessing the charge on solar QFs is appropriate," based upon the Study's results.[5] While the expedited nature of this proceeding before the Commission did not allow for the same extensive review and discussion of the Study with the ORS, the ORS's expert, Mr. Horii, finds the integration cost analysis in the Study to be acceptable, as I discuss further below.

IV. RESPONSE TO ORS WITNESS HORII

Q. PLEASE PROVIDE A SUMMARY OF ORS WITNESS HORII'S TESTIMONY IN REGARD TO THE ASTRAPÉ ANCILLARY SERVICE STUDY.

A. ORS Witness Horii agrees with the premise of the Study and recommends this Commission approve the Companies' proposed Integration Services Charges. He states that "[i]t is appropriate to recognize the Companies will incur additional integration costs associated with integrating large amounts of solar generation on the Companies' grid. As an initial step or on an interim basis, I recommend the Companies' solar integration services charges of $1.10/MWh for DEC and $2.39/MWh for DEP be approved."[6] Witness Horii goes on to say

[5] Duke Wintermantel Rebuttal Exhibit 1, at 9.
[6] ORS Horii Direct, at 23.

the Companies should conduct additional integration studies in the future, which aligns with the Companies' proposal to update the Study on a biennial basis. Further, I would add that Witness Horii's recent Direct Testimony filed in the DESC avoided cost case uses the Astrapé Study as a benchmark to justify his recommended adjustments for the DESC study supporting its Variable Integration Charge, again showing that he believes the results of the Astrapé Study are reasonable for the state of South Carolina.[7]

Q. WITNESS HORII RECOMMENDED THAT THE SISC VALUES PROPOSED BY THE COMPANIES BE APPROVED FOR THE INTERIM AND THAT THE COMPANIES CONTINUE TO STUDY THEIR COSTS FOR INTEGRATING INTERMITTENT, RENEWABLE GENERATION. DO YOU AGREE THAT WITNESS HORII'S APPROACH IS REASONABLE?

A. Yes. This is a reasonable recommendation and approach. The $1.10/MWh and $2.39/MWh charges are not unreasonable compared to other studies performed in other jurisdictions. The Existing Plus Transition solar penetration is 2,950 MW for DEP and 840 MW for DEC and the Study requires a total of 192 MW of additional operating reserves which is not extreme. As addressed throughout my Rebuttal Testimony, it is reasonable to update the Study's assumptions to more accurately account for changes over time. Therefore, to the extent that the Companies' systems, and solar facilities interconnected to the Companies' systems change over time, those changes can be appropriately identified in

[7] ORS Horii Direct, at 20-21, Docket No. 2019-184-E (filed Sept. 23, 2019)

future biennial reviews and updates provided to the SISC to most accurately reflect the Companies' actual ancillary services costs.

V. RESPONSE TO SOLAR INDUSTRY EXPERT WITNESSES

Q. PLEASE PROVIDE AN OVERVIEW OF THE CONCERNS RAISED BY BOTH SACE/CCL WITNESS KIRBY AND SBA WITNESS BURGESS REGARDING THE STUDY.

A. Intervenors sponsoring testimony on behalf of the solar industry in this proceeding had five main critiques of the Ancillary Service Study. SACE/CCL Witness Kirby and SBA Witness Burgess both raised three similar concerns and argued that:

(1) The $\text{LOLE}_{\text{FLEX}}$ reliability metric is inappropriate because it does not reflect NERC BAL Standards;

(2) DEC and DEP were inappropriately modeled as islands; and,

(3) The intra-hour volatility assumptions are overstated due to linearly scaling from the 2016 to 2017 data to the Existing Plus Transition solar penetration level.

SACE/CCL Witness Kirby raised two more concerns, and additionally argued that:

(4) The Study imposed higher reserve requirements 8,760 hours per year instead of limiting increased reserve requirements to times and conditions when increased solar generation might have reserve shortfalls; and,

(5) The Study did not allow for non-spinning reserves to be added instead of operating reserves.

Q. WERE ANY OF THESE CRITICISMS ALSO RAISED BY PARTIES IN THE RECENT NORTH CAROLINA AVOIDED COST PROCEEDING?

A. Yes. Criticisms (1), (2), and (3) were each raised and litigated in detail in the North Carolina avoided cost proceeding. As I explained above, the NC Public Staff extensively reviewed these critiques through collaboration with Astrapé and the Companies to better understand the Study. As a result, the NC Public Staff agreed with the Companies and Astrapé that the $\text{LOLE}_{\text{FLEX}}$ metric, modeling of DEC and DEP as islands, and intra-hour volatility assumptions utilized in the Study were appropriate for purposes of conducting the Study and developing the charge.[8] Based upon ORS Witness Horii's Direct Testimony accepting the analysis in the Study, he has similarly concluded that the assumptions and results of the Study were reasonable and appropriate for purposes of fixing an initial SISC, recognizing that the Companies have committed to biennially update the Study.

Q. IS IT FAIR TO SAY THAT EACH CRITICISM LODGED BY SACE/CCL AND THE SBA ARGUES FOR A LOWER COST INTEGRATION CHARGE?

A. Yes. Witness Snider's Rebuttal Testimony discusses areas surrounding the Integration Services Charge where the Companies took a conservative approach to ensure the charge was not overstated. Duke Witness Snider also explains

[8] Duke Wintermantel Rebuttal Exhibit 1, at 9-12.

how Duke's proposal fairly balanced both the solar QF's and the Companies' customers' interests.

Q. SACE/CCL WITNESS KIRBY AND SBA WITNESS BURGESS BOTH CRITICIZE THE USE OF THE $LOLE_{FLEX}$ METRIC. PLEASE REINTRODUCE THE $LOLE_{FLEX}$ METRIC USED TO QUANTIFY THE NEED FOR ADDITIONAL ANCILLARY SERVICES AS ADDITIONAL SOLAR IS ADDED TO THE SYSTEM.

A. As discussed in my Direct Testimony, the $LOLE_{FLEX}$ reliability metric is the number of loss of load events due to system flexibility constraints, calculated in events per year.[9] $LOLE_{FLEX}$ is intended to measure the ability of a system to carry enough reserves to follow its net load given 5-minute ahead perfect foresight.

Q. HOW MANY 5-MINUTE NERC BALANCING DEVIATIONS WOULD BE EXPECTED IN A SYSTEM TARGETING 0.1 $LOLE_{FLEX}$?

A. SERVM is not capable of identifying the frequency of 5-minute balancing deviations. While Witness Kirby and Witness Burgess attempt to characterize the $LOLE_{FLEX}$ metric as synonymous with measuring compliance with the NERC Balancing Standards, $LOLE_{FLEX}$ in SERVM does not directly measure balancing deviations as defined by NERC.

[9] Duke Wintermantel Direct, at 15.

Q. DO THE BALANCING REQUIREMENTS IMPOSED BY THE NERC CONTROL PERFORMANCE STANDARD 1 ("CPS1") AND BAL-001-2 BALANCING AUTHORITY ACE LIMIT ("BAAL") STANDARDS CONFLICT WITH THE 0.1 $\mathbf{LOLE_{FLEX}}$ METRIC TARGETED BY SERVM?

A. No. The balancing requirements imposed by NERC do not conflict with the 0.1 $LOLE_{FLEX}$ metric targeted by SERVM. The operating reserves targeted in SERVM required to meet the 0.1 $LOLE_{FLEX}$ are comparable to historical reserves provided by DEC and DEP, so future compliance with the NERC BAAL standards is expected to be consistent with historical compliance. However, the NERC standards and $LOLE_{FLEX}$ are correlated. If $LOLE_{FLEX}$ is allowed to increase substantially, it is expected that NERC CPS1 and BAAL standards would be violated more often.

Q. SACE/CCL WITNESS KIRBY FURTHER ASSERTS THAT THE $\mathbf{LOLE_{FLEX}}$ METRIC IS TOO STRINGENT BECAUSE IT REQUIRES 5-MINUTE BALANCING COMPARED TO NERC's CPS1 AND BAAL BALANCING REQUIREMENTS, WHICH MEASURES BALANCING DEVIATIONS AT 12 MONTHS AND 30 MINUTES RESPECTIVELY. HOW DO YOU RESPOND?

A. I disagree. Witness Kirby again mischaracterizes the $LOLE_{\mathbf{FLEX}}$ metric as being synonymous with NERC imbalances. $LOLE_{\mathbf{FLEX}}$ within SERVM is not capable of calculating minute-to-minute NERC imbalances. CPS1 and BAAL standard requirements account for imbalances based on 1-minute averages of area control error or "ACE" which accounts for independent variables associated with the frequency deviations across the entire Eastern Interconnection that I readily admit are not captured by SERVM. The LOLE$_{\mathbf{FLEX}}$ reliability metric is a simpler representation in that it is only measuring the ability of the conventional fleet to move from one net load value to the next 5-minute net load value with perfect foresight and to determine if there were enough operating reserves and therefore enough ramping capability to meet net load. The second-to-second and minute-to-minute ACE deviations as calculated in the NERC requirements are not being captured. This mischaracterization is misleading and should be rejected.

More importantly, just because the NERC BAAL standard limits the balancing calculations on a 30-minute basis does not mean that the utility is not consistently balancing to maintain reliability and to respond to ACE deviations over much shorter time periods. For example, Duke Witness Sam Holeman explains that if the ACE exceeds the BAAL limit for five consecutive minutes, a Duke system operator begins to receive alarms. At this point the system operator would take actions such as reducing or increasing on-line generation. If the ACE continued to exceed the BAAL, the operator would continue to get alarms every five minutes, possibly leading to more emergent actions such as curtailing solar output for excess energy emergencies. Accordingly, Duke Witness Holeman states that he finds the 5-minute balancing approach that Astrapé takes in its solar Integration Services Charge cost analysis to be reasonable from a system operator's perspective. I agree with Mr. Holeman that it is not appropriate from a modeling perspective to assume that DEC and DEP will operate with increased reliability risks up to the limits of violating the NERC Balancing Standards when solar is being added to the system for purposes of quantifying the integration costs caused by incremental net load volatility.

Q. BASED ON WITNESSES KIRBY'S AND BURGESS' ASSERTIONS THAT THE $LOLE_{FLEX}$ METRIC IS TOO STRINGENT, HOW WOULD THE RESULTS CHANGE IF THE $LOLE_{FLEX}$ METRIC WERE RELAXED?

A. As mentioned, the NC Public Staff raised a similar question. Astrapé performed additional calculations which demonstrated that if flexibility and reliability were measured at 1.0 events per year, the average ancillary services costs used in avoided cost rates would only decrease from $1.10/MWh to $1.03/MWh for DEC and $2.39/MWh to $2.35/MWh for DEP. This analysis shows the impact in ancillary services costs if the original 0.1 event per year metric is relaxed tenfold. Given that the cost differentials are quite small, and that the reserves held in the 0.1 $LOLE_{FLEX}$ base case compare well with historical reserves, Astrapé believes a 0.1 $LOLE_{FLEX}$ benchmark is reasonable and appropriate.

Q. IN YOUR OPINION, ARE MR. KIRBY'S AND MR. BURGESS' OBJECTIONS TO THE SUBJECTIVE NATURE OF THE LOLE$_{\text{FLEX}}$ METRIC OVERSTATED?

A. Yes. As pointed out in a 2016 Solar Integration Study Report produced by Idaho Power ("Idaho Integration Study"),[10] as favorably cited by Mr. Kirby,[11] the selected reliability level is "relatively immaterial" to the integration cost since both the base case and change case are subject to the same reliability requirement. Additionally, as I described in more detail previously, the sensitivity performed for the NC Public Staff showed that relaxing the LOLE$_{\text{FLEX}}$ metric did not have a substantial impact on the results.

Q. IN YOUR OPINION, IS IT FEASIBLE TO MODEL ANCILLARY SERVICES USING THE NERC CPS1 AND BAAL STANDARDS?

A. No. Neither the Companies nor Astrapé are aware of any recently-completed integration studies or currently-available modeling techniques that have attempted to exactly mimic the NERC CPS1 and BAAL standards.

Q. HAS SACE/CCL WITNESS KIRBY EXPRESSED AN OPINION ON WHETHER MODELING ANCILLARY SERVICES USING THE NERC CPS1 AND BAAL STANDARDS IS FEASIBLE?

A. Yes. Mr. Kirby stated in his affidavit in North Carolina that actually modeling the NERC BAAL standards "is currently an infeasible modeling effort."[12]

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[10] Solar Integration Study Report, Idaho Power, April 2016, *accessible at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20 STUDY%20REPORT.PDF ("Idaho Integration Study").
[11] SACE/CCL Kirby Direct, Appendix A at 10.
[12] See NCUC Docket No. E-100 Sub 158 SACE Initial Comments, at Attachment A, at 10 (filed Feb. 12, 2019).

However, his Direct Testimony in this proceeding now perplexingly discusses the NERC CPS1 and BAAL standards as potential alternative modeling methodologies.[13]

Q. TURNING TO WITNESS KIRBY'S AND WITNESS BURGESS' DIRECT TESTIMONY ABOUT MODELING DEC AND DEP AS ISLANDS, WHY IS IT APPROPRIATE FOR THE STUDY TO MODEL EACH UTILITY AS AN ISLAND?

A. There are several reasons it is appropriate to model the utilities as islands. First, both the DEC and DEP BAs are responsible for their own operating reserve requirements. These operating reserve requirements must be in the form of firm capacity and not non-firm purchases. While the Companies could hypothetically contract for additional intra-hour operating reserves from designated generating units in other BAs, this practice would require securing firm transmission service as well as a capacity and energy contract from the neighboring generating facility owner, which both would come at a cost.

Further, it is my understanding that the Joint Dispatch Agreement ("JDA") between DEC and DEP is an economic excess energy transfer tool that relies upon non-firm transmission and thus can only be used by the Companies to exchange economic non-firm energy—not the firm capacity that would be required to provide the intra-hour regulation needed to manage the variability in solar output necessary to meet the BA's balancing obligations. The JDA additionally is not designed to assist the Companies with contingency

[13] SACE/CCL Kirby Direct, at 19-22.

obligations; the JDA schedule actually freezes when a large generator contingency in either the DEC or DEP balancing authority area occurs. Due to these reasons, it was important for Astrapé to simulate the DEC and DEP BAs individually to understand the reliability impacts and costs of integrating additional solar in each BA.

Importantly, the Astrapé Study does recognize some reliability and economic capacity benefits provided by the market by modeling additional resources in the island simulations from which DEC and DEP can purchase.[14] However, these resources were not modeled as being available to manage unexpected intra-hour net load deviations, because, in the real world, they are not available intra-hour to provide regulation service necessary to maintain NERC BAL Standard compliance. The fact that DEC and DEP are interconnected with surrounding regions does not change the fact that ancillary services—in the form of incremental load following reserves, as specifically quantified in the Astrapé Study—are needed to integrate solar generation and that these ancillary services have a cost.

Q. IN RESPONSE TO WITNESS KIRBY'S DIRECT TESTIMONY ABOUT MODELING DEC AND DEP AS ISLANDS, DOES MODELING DEC AND DEP AS ISLANDS PRECLUDE THE CONSIDERATION OF THE BENEFITS OF INTERCONNECTED SYSTEMS?

A. No. Astrapé fully recognizes that there are intra-hour benefits of participating in an interconnected system. However, one of the premises of the Astrapé

[14] Duke Wintermantal Direct Exhibit 2, at 13.

Study is that the Companies should not be assumed to impose a larger burden on other BAs across the Interconnection after adding solar than what was assumed prior to adding solar. To do so would imply that neighboring BAs would bear the costs for Duke's integration of solar. Importantly, SERVM implicitly recognizes the benefits of participating in an interconnected system by modeling reserves in the no-solar case that are comparable to historical reserves.

Q. IS WITNESS KIRBY'S AND WITNESS BURGESS' POSITION THAT IT WAS INAPPROPRIATE TO MODEL THE DEC AND DEP BAS AS ISLANDS CONSISTENT WITH OTHER ANCILLARY SERVICES STUDIES SIMILARLY FOCUSED ON QUANTIFYING SOLAR INTEGRATION COSTS?

A. No. Modeling BAs as islands for purpose of quantifying solar integration costs is not uncommon. In the recent North Carolina avoided cost proceeding, the NC Public Staff reviewed a number of other renewable integration studies and found that "modeling utilities as load islands with limited or no ability to rely upon neighboring utilities for real-time solar and wind output fluctuations is not uncommon."[15] This aligns with my understanding as well.

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[15] Duke Wintermantel Rebuttal Exhibit 1, at 10.

Q. IN ADDITION TO THE CRITICISMS LISTED ABOVE, WITNESS KIRBY AND WITNESS BURGESS ALSO ARGUE THAT CALIFORNIA IS NOT SEEING INCREASING INTEGRATION COSTS AS INSTALLED SOLAR HAS INCREASED AND SUGGEST CALIFORNIA UTILITIES HAVE NOT ESTABLISHED INTEGRATION CHARGES IN AN EFFORT TO UNDERMINE THE VALIDITY OF THE ASTRAPÉ STUDY. HOW DO YOU RESPOND?

A. I disagree with Witnesses Kirby and Burgess. Contrary to their arguments, it is my understanding that utilities such as Southern California Edison and Pacific Gas & Electric in California have in fact experienced increased renewable integration costs and established integration charges.

As Witness Kirby correctly suggests, the process to develop updated wind and solar integration charges was not completed in California. However, he fails to mention that the utilities in California already had in place an integration charge utilized in their Renewable Portfolio Standard ("RPS") procurements as can be seen in Southern California Edison's 2018 Renewable Portfolio Standard Procurement Plan.[16]

In RPS procurements, Southern California Edison applies a $4.00/MWh variable integration cost component for wind resources and a $3.00/MWh variable integration cost component for solar resources. These integration cost

[16] Southern California Edison Company's (U 338-E) 2018 Final Renewable Portfolio Standard Procurement Plan, Volume 2, Appendix G, at 7, CPUC Rulemaking No. 18-07-003 (Apr. 2, 2019), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M306/K036/306036350.PDF.

rates were approved by the California Public Utilities Commission in 2014,[17] and have been left unchanged. In addition to the variable $3.00/MWh solar integration cost, Southern California Edison also includes an additional fixed cost component based on Southern California Edison's portfolio need to secure additional capacity from resources not already procured to meet its flexible and non-flexible resource adequacy requirements over the contract period. So while costs have not been updated since 2014, Southern California Edison does, in fact, apply an integration cost in their RPS solicitations that is greater than both the $1.10 /MWh and $2.39/MWh SISCs proposed by DEC and DEP. Therefore, Witness Kirby's arguments that California abandoned its efforts to quantify integration costs between 2015 and 2018 is misleading and should be dismissed.

Q. WITNESS KIRBY AND WITNESS BURGESS ALSO ARGUE THAT OPERATING RESERVES AND COSTS HAVE NOT INCREASED IN CALIFORNIA DUE TO THE INTEGRATION OF INTERMITTENT RENEWABLES. IS THIS A FAIR REPRESENTATION OF CALIFORNIA'S INTEGRATION OF INTERMITTENT RENEWABLE RESOURCES IN YOUR OPINION?

A. No. I specifically disagree with Witness Kirby's assertion that "operating reserve amounts and costs have not increased for the California Independent

[17] *Decision Conditionally Accepting 2014 Renewable Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan,* CPUC D. 14-11-042, Rulemaking 11-05-005 (Nov. 20, 2014), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K313/143313500.PDF.

System Operator ("CAISO") while [California] [has] integrated 20,000 MW of solar generation and 6,700 MW of wind generation."[18]

In fact, the CAISO 2016 Annual Market Performance Report states: "Ancillary service costs increased to $119 million, nearly doubling from $62 million in 2015.

> This represents an increase from 0.7 percent of total wholesale energy costs in 2015 to about 1.6 percent in 2016. This was primarily driven by the increased regulation requirements to manage variability of renewable resources…. In October [2016] the ISO introduced a new methodology for calculating requirements on an hourly basis. After this modification, regulation costs were about 80 percent higher than the same period in 2015."[19]

Further, Witness Kirby's referenced citation concerning CAISO[20] does not state, and therefore does not support, his assertion that operating reserve amounts and costs have not increased for the CAISO. As I explained above, Southern California Edison is currently using an integration charge of $3.00/MWh for solar in its RPS Procurements. Witness Kirby's misleading and incorrect statements attempting to benchmark to California should therefore be ignored.

Moreover, it is important to recognize that the Carolinas have much different weather patterns than California. As described in Duke Witness Holeman's Rebuttal Testimony, California experiences substantially more clear

[18] SACE/CCL Kirby Direct, at 13.
[19] http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.
[20] *See* California ISO, *What are we doing to green the grid?* (last accessed Sept. 9, 2019), *available at* http://www.caiso.com/informed/Pages/CleanGrid/default.aspx; *see also* California ISO, *Reports and bulletins keep you current* (last accessed Sept. 9, 2019), *available at* http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx.

sky days compared to the Carolinas and thus, would experience substantially different intra-hour volatility.

Q. ORS'S EXPERT, MR. HORII, IS FROM CALIFORNIA. DID HE MAKE SIMILAR ARGUMENTS?

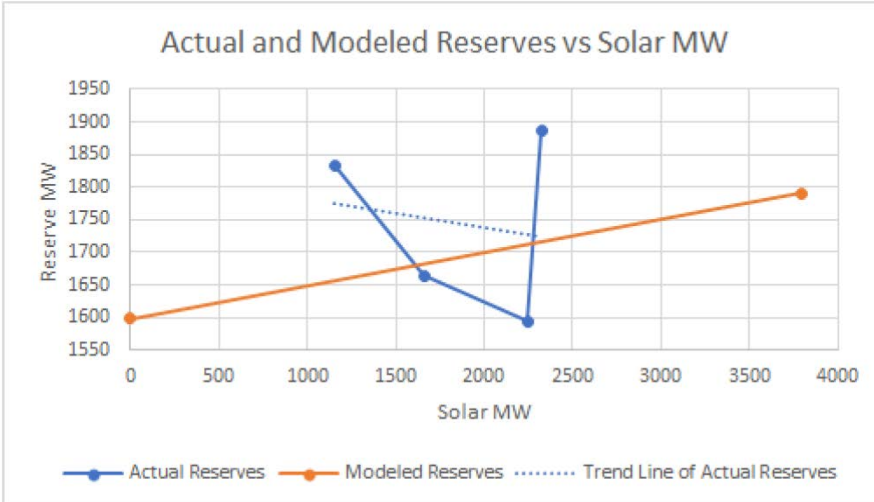
A. No. ORS Witness Horii testified that E3 has conducted "extensive work in California and Hawaii," and he testified that "increasing amounts of solar and wind generation can require additional ramping capability and reserves" which results in a "cost impact" which can include "additional generation plant required to provide additional flexible capacity." If Mr. Horii believed the Astrapé Study's findings and conclusions were inconsistent with the solar integration experience in California, presumably Mr. Horii would have put forward a similar critique.

Q. WITNESS KIRBY PLOTS THE 2015 – 2018 HISTORICAL OPERATING RESERVES PROVIDED BY THE COMPANIES AGAINST THE MODELED OPERATING RESERVES AND STATES THAT THE "ANCILLARY SERVICE STUDY'S PREDICTIONS ARE NOT ACCURATE."[21] DO YOU AGREE WITH WITNESS KIRBY'S ASSESSMENT?

A. No. I believe the comparison in Witness Kirby's Figure 1 (replicated below) illustrates the total 60 minute online ramping capability of the Ancillary Service Study is in line with, and not extremely below or above, the Companies' actual historical data.

[21] SACE/CCL Kirby Direct, at 9.

SACE/CCL Witness Kirby Figure 1



It is important to understand that it is erroneous to expect the Study to be precisely in line with the Companies' actual historical data due to various uncontrollable variables changing from year to year on the Companies' systems that result in variations in reserves unrelated to the integration of intermittent generation. Fuel prices, loads, generator availability, and resource mix all play a significant role in the amount of realized reserves that are actually experienced on the Companies' system year to year. For example, if coal resources are dispatched ahead of gas resources in a given year due to lower coal prices, then the realized operating reserves will likely be higher in that year because coal resources cannot cycle as quickly as gas resources and are often run overnight at minimum loading levels. Although it would be more economic for the Companies to operate the coal resource, it may have the ancillary effect of increasing the realized reserves for that year. Moreover, the Study modeled the Companies' system for the year 2020 reflecting 2020 load forecasts, resource mix, and fuel prices which are all different than the historical values. Further, Witness Kirby's criticisms are that the Study carries too high of operating reserves, but I do not agree that his own figure supports his conclusion. If anything, the modeled reserves are on the lower end of actual, historical operating reserves. This comparison of historical operating reserves and modeled operating reserves serves as a reasonable calibration that operating reserves are not understated or overstated in the Study. Further, these modeled operating reserves in the no solar case produce an $LOLE_{FLEX}$ of 0.1 events per year, further demonstrating that the reliability metric applied in the Study is reasonable compared to historical reserves.

Q. DOES THE HISTORICAL DATA REFERENCED BY MR. KIRBY ACTUALLY SHOW THAT OPERATING RESERVES HAVE BEEN INCREASED OVER THE 2015 – 2018 TIME PERIOD AS SOLAR HAS BEEN ADDED?

A. Yes. After analyzing the Companies' historical operating reserve data, I found that the 2015 operating reserve data was an outlier due to higher coal dispatch as explained in my above example. If coal units are left online, then it is natural to have higher operating reserves versus relying more on gas which can more easily cycle on and off with less operating reserves. As also discussed previously, many factors drive operating reserves from year to year but in the modeling exercise each of these variables are fixed in order to accurately measure increased reserves due to increases in solar. The argument that the Study is incorrect or that solar is not impacting operating reserves because there is not a linear increase in operating reserves historically as solar increases is flawed and ignores that other variables unrelated to increases in solar penetration historically cause the realized operating reserves to change from year to year. Importantly, the Ancillary Service Study only isolates the solar impact on the Companies' system (and all other assumptions including load, fuel prices, resource mix stay constant), and in doing so identifies a linear increase in operating reserves which bisects the historical operating reserve calibration shown in SACE/CCL Witness Kirby Figure 1 (reproduced above for ease of reference) giving further credence to the Study.

Q. WITNESS KIRBY ALSO ARGUES THAT THE COMPARISON SHOULD BE MODIFIED TO REDUCE THE HISTORICAL VALUES BY 400 MW WHICH ARE ASSUMED TO BE HELD FOR CONTINGENCY RESERVES. IS THIS AN ACCURATE ASSUMPTION?

A. No. Both the operating reserves modeled in SERVM and historical datasets include all online 60-minute ramping capability which would include all spinning reserves. SERVM makes the conservative assumption that spinning reserves held for contingencies are also available to address solar intermittency. To remove 400 MW from the historical data would mean that 400 MW would also need to be removed from the modeled data to have a valid comparison. Witness Kirby's suggestion is extremely misleading and should be rejected.

Q. WITNESS KIRBY STATES THAT THE ANCILLARY SERVICE STUDY BASED ITS SOLAR VARIABILITY ESTIMATE ON ONE YEAR OF DATA COLLECTED BETWEEN OCTOBER 2016 AND SEPTEMBER 2017 AND THAT THE SOLAR FLEET HAD GROWN CONSIDERABLY FROM THE 244 – 431 MW THAT WERE OPERATING DURING THAT TEST YEAR.[22] IS THIS A CORRECT STATEMENT?

A. No. The MW levels Witness Kirby identifies actually only represent the DEC solar capacity during that timeframe which is extremely misleading. The DEP solar capacity in the historical data during this timeframe approaches 1,500 MW, which would include substantial diversity benefit within the historical data.

Q. WITNESS KIRBY CRITICIZES THE STUDY BECAUSE THE 2016 – 2017 DATA WAS USED FOR THE EXISTING PLUS TRANSITION SOLAR PENETRATION LEVEL. PLEASE EXPLAIN WHY THE DATA WAS USED.

A. When Astrapé began developing the Study in late 2017, the historic vintage of intra-hour volatility data for the period October 2016 – September 2017 was the best and most current data available. The Companies do not dispute that use of more current solar volatility data can impact assumptions over time, especially as market conditions around the types of solar facilities being built in South Carolina and North Carolina evolve in the future. For this reason, the

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[22] SACE/CCL Kirby Direct, at 25.

Companies advocate for updating the historic volatility data biennially in future avoided costs proceedings, just as it updates other aspects of its avoided costs to recognize changing resource mixes, load forecasts, gas forecasts, etc., in order for the data to be updated and most accurate. Thus, at the time the diversity of the Companies' solar fleet begins to exemplify that intra-hour volatility is decreasing, the data can then be updated and simulated to more accurately reflect that occurrence.

The Study did, however, self-identify that it is difficult to project intra-hour solar volatility at higher penetrations of future solar capacity, and took steps in the long-term +1,500 MW solar scenarios to recognize the potential benefits of geographic diversity. However, at the time of the Study there was not enough actual data to understand how geographical diversity at higher solar penetrations would impact intra-hour volatility; consequently, these high penetration levels are not used to determine the SISC. Also, the Companies believe that larger utility-scale solar facilities will be coming online that could dampen or remove any geographical diversity benefit expected with larger solar penetrations.

The Companies also reemphasize that historic solar volatility data actually relied upon in developing the SISC is reasonably representative of the near-term development of the "Existing Plus Transition" level of solar in DEC and DEP. Importantly, this near-term development of solar QF projects reflects "existing" solar QFs, mostly 5 MW (NC) and 2 MW (SC) in capacity, along with incremental development of "transition MW" which are primarily legacy

5 MW QFs in North Carolina. Accordingly, the Companies and Astrapé continue to support the quantification of ancillary services costs relied upon in the Astrapé Study as reasonable and appropriate for purposes of the Integration Services Charge proposed in this proceeding and will plan to update the solar volatility data including reviewing the potential for increased geographic diversity in the next biennial proceeding.

Q. WITNESS KIRBY ALSO MAINTAINS THAT SOLAR INTRA-HOUR VOLATILITY DECLINES ACCORDING TO THE FOLLOWING FORMULA:

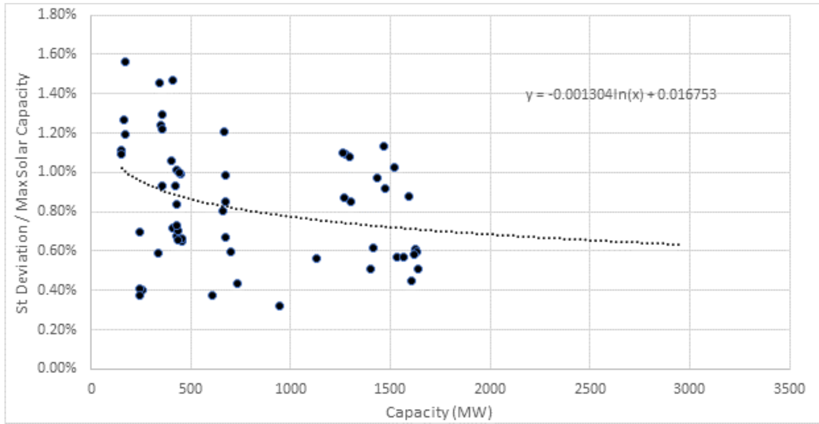
$$1 / \sqrt{\frac{\textit{Existing Plus Transition Capacity}}{\textit{Capacity from Historical Dataset}}}$$ [23]

IS THERE EMPIRICAL EVIDENCE FOR THIS RELATIONSHIP?

A. No. Witness Kirby's formula is not appropriate as it is not based on the observed diversity benefit of increasing solar. To demonstrate, the Companies used Witness Kirby's analysis of 5-minute solar data from 2016 – 2018 and plotted the monthly normalized standard deviation (standard deviation/max capacity) on the y axis and the solar capacity on the x axis to show how volatility/variability changes over different solar penetrations. This data represents the individual DEC and DEP data on the same chart, and provides a curve fit that is intuitive. Figure 1 shows that by utilizing Witness Kirby's formula, volatility was reduced and that the discount is more significant at lower solar capacity levels but flattens out as additional solar is added to the system.

[23] *See* SACE Initial Comments, Attachment 1, at 15, NCUC Docket No. E-100, Sub 158 (filed Feb. 12, 2019); SACE/CCL Kirby Direct, at 21-25.

Figure 1



Applying the curve fit from the above plot to the actual historical volatility data used in the Study and to the Existing Plus Transition capacity levels, the Companies estimate the volatility discount at much less than the 39% (1-61% = 39%) recommendation provided by Witness Kirby. Figure 2 shows a 13% discount for DEC and a 17% discount for DEP based on the normalized standard deviation (standard deviation / max solar capacity).

Figure 2

	DEC	**Standard Dev/Capacity**	**DEP**	**Standard Dev/Capacity**
October 2016 - September 2017	338	0.92%	1087	0.77%
Existing Plus Transition	840	0.80%	2950	0.64%

Discounted Value	87%	**Discounted Value**	83%

However, the Companies emphasize that these are projections, not guaranteed to materialize and do not incorporate the impact that large solar projects may have on volatility when added to the system. These projections simply extrapolate the diversity benefit seen over the 2016 – 2018 time period which includes mostly small distribution-connected QF solar projects. Given the uncertainty in diversity benefit, the Companies believe it is more appropriate to rely on actual historical data to set ancillary services cost rates at the time of the Study and to perform updates every two years. New data not available during the initial completion of the Study will continually provide more guidance on solar volatility assumptions.

Q. WITNESS KIRBY STATES THE "STUDY IMPOSED THE HIGHER RESERVE REQUIREMENTS 8,760 HOURS PER YEAR INSTEAD OF LIMITING INCREASED RESERVE REQUIREMENTS TO TIMES AND CONDITIONS WHEN INCREASED SOLAR GENERATION MIGHT CAUSE RESERVE SHORTFALLS."[24] IS THIS AN ACCURATE STATEMENT?

A. No. The Ancillary Service Study recognized that operating reserve requirements were generally exceeded in off-peak hours due to generator constraints such as minimum uptimes, minimum downtimes, startup times, and startup costs. Therefore, increasing the target reserves in all hours would only influence on-peak commitment decisions. It is true that commitment decisions for on-peak would also affect reserves in off-peak hours since those units would also have operating

[24] SACE/CCL Kirby Direct, at 4.

constraints, but in general the reserves target in off-peak hours is expected to be immaterial to the incremental commitment decisions. Witness Kirby's estimate of a 58% discount for tuned reserve requirements is based on a faulty understanding of how the reserve targets were implemented in SERVM. This proposed discount should be rejected because, as stated above, the Study did not manually increase operating reserves in all 8,760 hours because many hours had already met the enhanced reserve targets.

Q. WITNESS KIRBY STATES THAT THE STUDY REQUIRED THE ADDED RESERVES TO COME FROM ONLINE, SPINNING GENERATION RATHER THAN ALLOWING LOWER COST NON-SPINNING RESOURCES TO PROVIDE SOME OR ALL OF THE ADDED RESERVES, GREATLY INCREASING THE COST OF SUPPLYING ADDITIONAL RESERVES. IS THIS ACCURATE?

A. No. Witness Kirby's assertion that non-spinning resources were not allowed to reduce $LOLE_{FLEX}$ is inaccurate and should be rejected. All simulations before and after solar was added allowed for non-spinning reserves or quick start resources to be turned on to prevent $LOLE_{FLEX}$ events. Therefore, his argument is flawed and should be rejected. Moreover, Witness Kirby additionally argues for an extreme 85% discount to the SISC based upon his flawed analysis, which is both unsupported by the modeling underlying in the Study and unreasonable on its face. It is also perplexing that Witness Kirby stated in response to Duke's data request SACE/CCL 1-1 that "DEC and DEP should not use contingency reserves required by NERC and SERC specified in BAL-002-02 to accommodate intra-hour solar volatility," but at the same time states that non-spinning resources should be allowed to manage the integration of solar. Further, the study conservatively allows for spinning reserves to accommodate intra-hour ramping which without this accommodation would actually increase integration costs as compared to Witness Kirby's suggested modeling.

It should also be noted that during contingency events when significant generation goes on outage, the model provides conservative assumptions to the ramp down of those units. This means that the model allows the generator to ramp down over 60 minutes rather than an instantaneous decrease to zero. These generator ramp down assumptions are included in both the no solar and with solar case.

Q. LAST, WITNESS KIRBY RECOMMENDS THE DEC SISC BE ADJUSTED DOWNWARD TO $0.05/MWH AND THE DEP SISC BE ADJUSTED DOWNWARD TO $0.11/MWH. ARE THESE ADJUSTMENTS REASONABLE?

A. No. The Companies requested all analysis from Witness Kirby explaining that the DEC charge should be reduced from $1.10/MWh to $.05/MWh and the DEP charge should be reduced from $2.39/MWh be $0.11/MWh. After reviewing his analysis, his proposal is contrived merely based on high level estimates that contain no additional modeling of the DEC or DEP systems and therefore lacks an analytic basis. Further, several reasons support rejecting his recommendations outright.

First, to hypothetically assume for the sake of argument that any of his adjustments are appropriate (which they are not), the SISC values recommended by Witness Kirby are so significantly lower than values included in other integration studies that I question whether Witness Kirby's own analysis contains an error. Again, I am not aware of any actual modeling performed by Witness Kirby to arrive at these values.

Additionally, the individual discounts Witness Kirby utilized to recommend these adjustments are based upon his incorrect criticisms regarding the Study, which I have refuted and dismissed as inaccurate throughout my Rebuttal Testimony. For example, Witness Kirby includes an extremely significant 85% discount due to his inaccurate assertion that the Study's model did not allow the use of non-spinning reserves. He also applies a further 58% discount due to his inaccurate assertion that operating reserves were increased in all 8,760 hours, as well as a 24% discount due to his inaccurate assertion that the geographical diversity will reduce intra-hour volatility by 24% by the time the Existing Plus Transition solar penetration level is on the system. In summary, Witness Kirby's recommendation to adjust DEC's SISC and DEP's SISC based upon inaccurate critiques of the Study should be rejected.

Q. WITNESS BURGESS ALLEGES A DOUBLE COUNTING PROBLEM IN THE STUDY DUE TO TWO DIFFERENT MODELS BEING USED TO CALCULATE THE COMPANIES' AVOIDED ENERGY COSTS AS COMPARED TO THE SISC. DID THE STUDY "DOUBLE COUNT"[25] AVOIDED ENERGY COSTS SO AS TO UNNECESSARILY INCREASE THE SISC?

A. No. There was no "double counting" due to the use of one model for calculating avoided energy costs (PROSYM) and another model for calculating ancillary services costs (SERVM). In fact, the Companies and Astrapé were intentionally careful to ensure the two modeling procedures did not double count costs.

The Ancillary Service Study is an intra-hour modeling Study that only takes into account the additional costs of increasing load following reserves between two cases with the same amount of solar. If anything, as discussed by Duke Witness Snider, additional costs relative to solar were excluded from the SISC calculation because the avoided energy costs calculation assume a 100 MW resource is added in all hours of the year. This means that for avoided energy cost calculations, there is no additional ramping or cycling of resources included in the avoided energy calculation, which occurs during real world operations and could be appropriate to include. The Study also does not capture these redispatch costs since both the base and change cases in which the SISC costs were calculated include the same amount of solar resources. Therefore, costs were certainly not double counted, and instead potentially lower than the

[25] SBA Burgess Direct, at 73.

actual costs the Companies are incurring and overstating the avoided energy payments made to QF developers.

Q. DOES WITNESS BURGESS PROVIDE ANY EVIDENCE FOR HIS ARGUMENT THAT "THE UNIT COMMITMENT AND DISPATCH PROCEDURES MODELED IN THE STUDY MAY NOT MATCH DUKE'S ACTUAL PRACTICES AND MAY TEND TO OVERESTIMATE INTEGRATION COSTS"[26]?

A. No. Witness Burgess' Direct Testimony raises this argument as one of the so-called "flaws" in the Study without providing any elaboration or support. This general, unsupported assertion should be rejected as there is no basis to support Witness Burgess' erroneous conclusion.

Q. SIMILAR TO WITNESS KIRBY, WITNESS BURGESS PROVIDES AN EXTREME RECOMMENDATION TO REDUCE THE DEP INTEGRATION COSTS FROM $2.39/MWh to $0.52/MWh BASED ON PERCENTAGE DISCOUNTS HE HAS ASSUMED FOR THE CHARGE. PLEASE RESPOND TO WITNESS BURGESS'S PROPOSED DISCOUNTS.

A. Similar to Witness Kirby, the Companies have requested all analysis and models used to determine the proposed discounts but have not received any to date from Witness Burgess. The Companies are not aware of any modeling performed by Witness Burgess. Each of the modifications that Witness Burgess raises have been refuted previously my Rebuttal Testimony.

[26] SBA Burgess Direct, at 73.

The first discount, while only 2%, represents the results of the Study if the $LOLE_{FLEX}$ metric is reduced by tenfold from 0.1 events per year to 1 event per year. As stated previously, this discount is not warranted because the modeled operating reserves compare well to historical operating resolves meaning that the 0.1 events per year threshold is reasonable and appropriate. As noted above, while the NC Public Staff originally requested this analysis, they did not advocate that the 0.1 $LOLE_{FLEX}$ metric was overly stringent.[27]

The second discount refers to a 35% discount due to his inaccurate assertion that the geographical diversity will reduce intra-hour volatility by 35% by the time the Existing Plus Transition solar penetration level is on the system. I have previously explained why the intra-hour volatility assumed by the Companies in the Study is appropriate and why this 35% discount should be rejected.

The third reduction applies a 52% discount based upon Witness Burgess' inaccurate assertion that operating reserves were increased in all 8,760 hours. As I explain above, his argument is based on a faulty understanding of how the reserve targets were implemented in SERVM, because the Study did not manually increase operating reserves in all 8,760 hours as many hours had already met the enhanced reserve targets.

The fourth and fifth reductions apply two separate 15% reductions due to the inaccurate assertion that the Companies should not be modeled as islands. Witness Burgess relies on the sensitivity performed by the Companies that was

[27] Duke Wintermantel Rebuttal Exhibit 1, at 13-14.

conducted to understand the maximum impact of combining the BAs which assumed no transmission limits and that the resources were being dispatched to a single load. Combining the BAs is an inappropriate analysis and does not reflect the reality of the current operating framework of the DEC and DEP BAs which are required to carry their own operating reserve requirements. Again, the NC Public Staff initially requested this analysis and ultimately agreed that modeling the DEC and DEP BAs as load islands was reasonable.[28] Burgess also assigns an additional 15% discount based on the use of external markets, which I explain above cannot be relied upon to serve operating reserves to manage intra-hour solar volatility. As discussed previously, firm capacity is required to meet NERC obligations. Thus, each of these proposed discounts are not warranted and are unsupported.

[28] Duke Wintermantel Rebuttal Exhibit 1, at 9-10.

VI. BENCHMARKING TO OTHER INTEGRATION COST STUDIES

Q. DO YOU BELIEVE THAT BENCHMARKING TO OTHER RENEWABLE INTEGRATION STUDIES CAN INFORM THE REASONABLENESS OF THE ASTRAPÉ STUDY'S RESULTS, AS WELL AS THE REASONABLENESS OF THE RECOMMENDATIONS PUT FORWARD BY SACE/CCL WITNESS KIRBY AND SBA WITNESS BURGESS?

A. At a general order of magnitude level, yes. Obviously each utility's power system has a different load profile, resource mix, and expected solar output, but I do think it is reasonable to consider the cost to integrate increasing penetrations of solar across studies as a function of the MWs of capacity installed on the modeled utility's system. For example, DESC is sponsoring a $3.52/MWh solar integration charge to integrate its baseline solar levels of 336 MW – 404 MW. This obviously reflects a significantly higher modeled cost to integrate lower amounts of solar into the DESC system than the Astrapé Study for either DEC ($1.10/MWh) or DEP ($2.39).

Q. PLEASE PROVIDE A SUMMARY OF THE NC PUBLIC STAFF'S BENCHMARKING COMPARISON OF THE STUDY TO OTHER RENEWABLE INTEGRATION STUDIES.

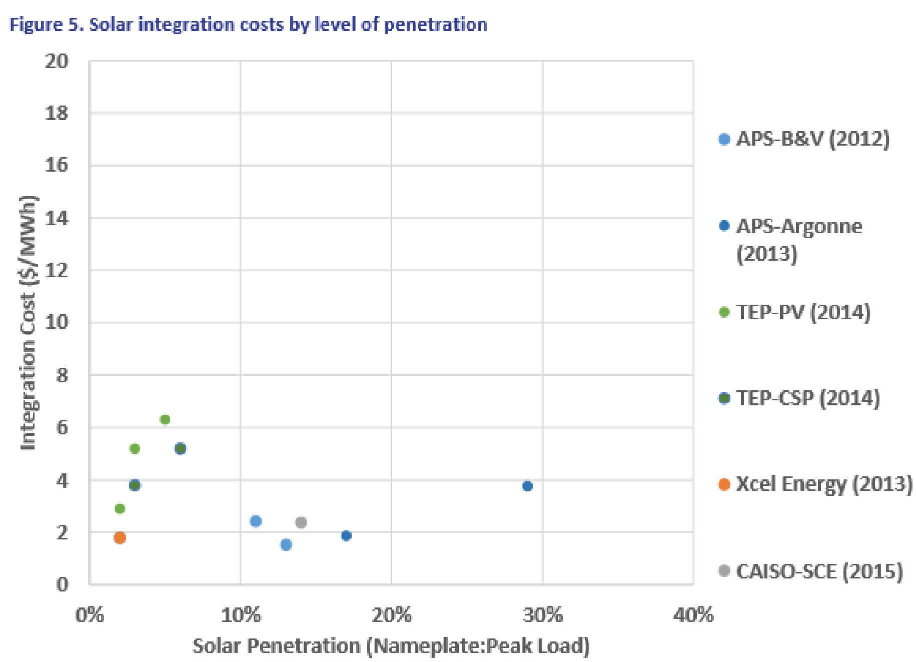
A. The NC Public Staff reviewed seven (7) other recent solar and wind integration studies, and found that ""[w]hile the approach taken in the integration studies was different, the NC Public Staff's review indicated that Duke's proposed

SISC is generally reasonable and within the range of the other studies" that the Public Staff reviewed.[29]

Q. IN ADDITION TO THE BENCHMARKING UNDERTAKING BY THE NC PUBLIC STAFF, ARE YOU FAMILIAR WITH ANY OTHER SURVEYS OF SOLAR INTEGRATION CHARGES?

A. Yes, a 2015 Synapse Energy Economics[30] study provides a summary of charges as laid out in my Figure 3 below. In summary, these charges are in line with or higher than the solar integration charges proposed by the Ancillary Service Study.

<u>Figure 3</u>



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[29] Duke Wintermantel Rebuttal Exhibit 1, at 9.

[30] *A Solved Problem: Existing measures provide low-cost wind and solar integration*, at 16 (Aug. 25, 2015), *accessible at* https://www.synapse-energy.com/sites/default/files/A-Solved-Problem-15-088.pdf (Last visited Oct. 1, 2019).

In addition, I am aware that National Renewable Energy Laboratory performed a benchmarking study[31] in 2013 analyzing wind and solar integration charges. For solar, it included solar integration charge results for Bonneville Power Authority ("BPA"), Public Service Colorado ("PSCO"), and Arizona Public Service ("APS"). The surveys shows a $0.21/kW-month cost for BPA to integrate 13 MWs of solar. If converted to $/MWh assuming a 25% solar capacity factor, it equates to $1.15/MWh. PSCO included a range of solar integration charges ranging from $1.25/MWh to $6.05/MWh to integrate 200 MW – 800 MW of solar. APS included a range of charges from $1.53/MWh to $3.04/MWh to integrate 1,038 MW to 1,669 MW of solar. These solar integration studies completed in other jurisdictions generally align with (and most are higher than) the results of the Astrapé Study and suggest that the $1.10/MWh integration charge in DEC and $2.39/MWh charge in DEP are reasonable.

[31] *See* https://www.nrel.gov/docs/fy13osti/57583.pdf (March 2013).

Q. BENCHMARKING AGAINST THE SOLAR INTEGRATION CHARGES PRODUCED IN OTHER JURISDICTIONS, ARE SACE/CCL WITNESS KIRBY'S RECOMMENDATIONS OF $0.05/MWh FOR DEC AND $0.11/MWh FOR DEP AND SBA WITNESS BURGESS' RECOMMENDATION OF $0.52/MWh FOR DEP IN LINE WITH OTHER STUDIES?

A. No. Mr. Kirby's and Mr. Burgess' recommendations are lower than the charges presented in these other studies including the charge being sponsored by DESC in South Carolina.

Q. DO THE OVERALL RESULTS OF THE STUDY IN TERMS OF INCREMENTAL LOAD FOLLOWING OPERATING RESERVES SIMILARLY SUPPORT THE REASONABLENESS OF THE STUDY?

A. Yes. As recognized by the NC Public Staff, it is important to recognize that the "the quantity of incremental load following reserves appears to be reasonable compared to the capacity of solar generation resources on the system."[32] More specifically, the Study finds that 26 MW of additional load following operating reserves are required to integrate 840 MW of solar in DEC, while 166 MW of additional load following operating reserves are required to integrate 2,950 MW of solar in DEP. I concur with the Public Staff's conclusion.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[32] Duke Wintermantel Rebuttal Exhibit 1, at 14.

NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

June 21, 2019

Ms. M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 158 - Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2018

Dear Ms. Jarvis:

In connection with the above-captioned docket, I transmit herewith for filing on behalf of the Public Staff the Testimony of Jeff Thomas, Utilities Engineer, Electric Division, and the Testimony of John R. Hinton, Director, Economic Research Division.

By copy of this letter, we are providing copies to all other parties of record.

Sincerely,

/s/ Tim R. Dodge
Staff Attorney
tim.dodge@psncuc.nc.gov

Executive Director	Communications	Economic Research	Legal	Transportation
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of		
Biennial Determination of Avoided	)	TESTIMONY OF
Cost Rates for Electric Utility	)	JEFF THOMAS
Purchases from Qualifying Facilities	)	PUBLIC STAFF – NORTH
– 2018	)	CAROLINA UTILITIES
	)	COMMISSION
	)	

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are included in Exhibit A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's position on proposed modifications to the avoided cost rates of Duke Energy Progress, LLC ("DEP"), Duke Energy Carolinas, LLC ("DEC") (collectively, "Duke"), and Dominion Energy North Carolina ("DENC") (collectively, "the Utilities"). Specifically, I will address the following issues identified by the Commission as meriting consideration at an evidentiary hearing:

I. Duke's quantification of ancillary services cost of integrating Qualifying Facility ("QF") solar;

II. Duke's proposed solar integration charge "average cost" rate design and biennial update;

III. DENC's proposed re-dispatch charge ("RDC");

IV. NCSEA's and Public Staff's proposals related to differing ancillary services costs for innovative QFs;

V. Duke's Proposed Modifications to the Standard Terms and Conditions as related to the Energy Storage Protocol;

VI. The stipulation between Duke and the Public Staff filed on April 18, 2019, related to energy and capacity rate design.

I will also propose rule changes to R8-64 and R8-71 that are related to the rate design stipulation. My testimony should be considered in conjunction with that of Public Staff witness Bob Hinton.

I. <u>Duke's Quantification of Ancillary Services Cost of Integrating QF Solar</u>

Q. WHAT IS THE PURPOSE OF DUKE'S PROPOSED SOLAR INTEGRATION SERVICES CHARGE?

A. Duke asserts that the purpose of the Solar Integration Services Charge ("SISC") is to quantify and recoup the costs it incurs from to the injection of power from intermittent QFs into its electric grid. The general argument is that the intermittent and non-dispatchable nature of renewable technologies, such as standalone solar photovoltaics ("PV"), results in additional system costs to integrate these sources of energy. This issue is exacerbated because the majority of the solar PV on the Utilities' grids are "must-take" facilities under the federal Public Utilities Regulatory Policies Act of 1978("PURPA"), with limited ability for the Utilities to curtail or dispatch these facilities outside of emergency situations.

Public Staff witness Dustin Metz testified on the issue of integrating significant solar QF capacity in the 2016 biennial avoided cost proceeding, Docket No. E-100, Sub 148 ("Sub 148"). Mr. Metz explained that as solar QF capacity increases under PURPA, Duke faces "increasing operational challenges as they seek to maintain the proper amount of contingency reserves that can be 'ramped up' and 'ramped down' in real time to meet resulting demand/supply imbalances."[1]

Q. DOES THE PUBLIC STAFF AGREE WITH THE GENERAL ARGUMENT PUT FORTH BY DUKE TO JUSTIFY THE PROPOSED SISC?

A. Yes. The Public Staff agrees that integrating intermittent, non-dispatchable energy sources cause system operators to make decisions and deploy the fleet of Utility-owned generation assets in ways that can increase costs to ratepayers. This concept is generally uncontroverted within this proceeding. These increased system

[1] *See* March 28, 2017, testimony of Dustin R. Metz in Docket No. E-100, Sub 148, at 6-7.

costs, reflecting increased fuel consumption and operations and maintenance expenses, are ultimately passed on to ratepayers through base rates and annual fuel rider adjustments.

Q. PLEASE PROVIDE AN EXAMPLE OF THE INCREASED COSTS THAT ARE PASSED ON TO RATEPAYERS.

A. As noted in the testimony of Duke witness Glen A. Snider, Duke's SISC is designed to recoup costs stemming from the increased ancillary services required to have sufficient on-line generation ramping capabilities to meet intra-hour unplanned fluctuations in solar output (such as cloud cover). These increased system costs are due to (1) thermal units operating outside their optimal output range, and (2) additional dispatchable units operating in standby mode, ready to respond within minutes to meet applicable North American Electric Reliability Corporation ("NERC") balancing requirements.[2]

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY DUKE TO QUANTIFY THESE COSTS.

A. Duke contracted with Astrapé Consulting ("Astrapé"), which utilized a proprietary reliability-based probabilistic model to determine the level of frequency regulation reserves necessary to meet load in five

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[2] Direct Testimony of Glen A. Snider at 36-37.

minute increments. As solar PV penetration increases in iterative model runs, the amount of frequency regulation reserves are increased to maintain the same level of system reliability as in the base case with no solar.

Q. DID THE PUBLIC STAFF IDENTIFY ISSUES WITH DUKE'S QUANTIFICATION OF THE SISC?

A. Yes. We identified four technical concerns with the Astrapé study in our initial comments.[3] As described in our reply comments, we later withdrew some of these concerns based upon additional discovery and communication with Duke.[4] The Public Staff also supported the analysis of Southern Alliance for Clean Energy ("SACE") witness Kirby of the reliability standards imposed on the model by Duke and Astrapé.

Q. PLEASE BRIEFLY SUMMARIZE YOUR CONCERNS WITH THE ASTRAPÉ STUDY.

A. The Public Staff's initial technical concerns regarding the SISC focused on the following items:

[3] One additional concern related to the biennial update, which is addressed later in this testimony.

[4] Reply Comments of the Public Staff at 17.

- The Astrapé model portrayed DEC and DEP as load islands, unable to rely on each other or neighboring utilities and regional transmission organizations ("RTOs") to meet the intra-hour fluctuations in demand and solar output.[5]
- The justification for the "base case", which included no solar capacity, excluding even utility-owned solar resources.[6]
- The limited amount of data used to quantify solar volatility on five minute intervals, and the potential for inaccuracy of the study's estimates of solar volatility, and therefore the integration costs, due to the geographical diversity of future solar generation facilities.[7]
- The modeler's addition of "load following up" reserves and the exclusion of other types of ancillary services that are capable of meeting intra-hour fluctuations in real time.[8]
- The assertion, based on the analysis of SACE witness Kirby, that if Duke used a reliability standard that was too stringent, it would drive up the amount of ancillary reserves required to meet intra-

[5] Initial Statement of the Public Staff at 39. DEP and DEC were able to rely on market purchases to meet capacity shortfalls (i.e., load exceeds demand with all generation units at maximum production), but not ramping shortfalls (i.e., demand increases faster than on-line generation units can ramp up output).
[6] Id. at 39-40.
[7] Id. at 40-41.
[8] Id. at 42.

hour fluctuations in solar output, thus resulting in integration cost estimates that are higher than actual costs incurred.[9]

Q. HAS DUKE WORKED WITH THE PUBLIC STAFF TO RESOLVE THESE CONCERNS?

A. Yes. Both Duke and Astrapé made technical staff available for multiple conference calls, responded to multiple data requests, and provided additional analysis, some of which is included in Duke's Reply Comments.[10]

Q. IS THE PUBLIC STAFF AWARE OF ANY OTHER INTEGRATION STUDIES UTILIZED BY OTHER UTILITIES?

A. Yes. The Public Staff performed a brief review of integration studies from several other utilities to compare methodologies, assess how the studies were conducted, whether the utilities were modeled as load islands, and what metrics were used to evaluate the system impact of intermittent resources. The studies, a summary of which is included as Exhibit B, are listed below by utility, generation technology, and study year:

- Xcel Energy (Public Service Company of Colorado), wind, 2011;
- Arizona Public Service, solar, 2012;

[9] Reply comments of the Public Staff at 18.
[10] Duke Reply Comments at 92-94.

- Xcel Energy (Public Service Company of Colorado), solar, 2013;
- Idaho Power, wind, 2013;
- Xcel Energy (Public Service Company of Colorado), solar, 2016;
- Idaho Power, wind, 2016;
- South Carolina Electric & Gas Company, solar, 2019.

While every approach taken in the integration studies was different, the Public Staff's review indicated that Duke's proposed SISC is generally reasonable and within the range of the other studies.

Q. WHY DOES THE PUBLIC STAFF NO LONGER BELIEVE THAT MODELING DEC AND DEP AS LOAD ISLANDS IS INAPPROPRIATE?

A. The Public Staff had a conference call with Duke system operators, who spoke in detail about the process for scheduling the load following reserves necessary to respond to intra-hourly fluctuations in solar output and load. This process does not incorporate any data from other utilities; that is, when DEP sets its required ancillary services for a particular day or hour, it does not consider the state of the DEC system. In addition, Duke's reply comments and the testimony of witness Nick Wintermantel provide a reasonable rationale as to why the utilities are modeled as load islands for the purposes of intra-hour regulation reserves – specifically, the discussion that while the Joint Dispatch Agreement between DEC and DEP allows for excess energy transfers of non-firm energy, it does not support the firm capacity that would be required to provide the intra hour ancillary services needed to manage the variability in solar output.[11]

Finally, the Public Staff reviewed intermittent generation integration cost studies from several other states, and found that modeling utilities as load islands with limited or no ability to rely upon neighboring utilities for real-time solar and wind output fluctuations is not uncommon.[12] Several of these studies allowed the utility to purchase energy and capacity from neighboring utilities, but not for the purposes of maintaining reserves – similar to how the Astrapé model portrayed DEC and DEP.[13]

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT IT IS APPROPRIATE TO MODEL A BASE CASE WITH NO SOLAR?

A. By removing all solar from the base case and then studying the integration cost of all solar, Duke effectively aggregates the system costs imposed by both QF solar and utility-owned solar. Solar QFs

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[11] *Id* at 86-91; Direct Testimony of Nick Wintermantel, at 27.

[12] The Public Staff found that the following studies modeled their utilities as "load islands" for the purposes of real time operations (utility, generation technology, study year): Arizona Public Service, solar PV, 2012; Idaho Power, wind, 2013; Idaho Power, wind, 2016; SCE&G, solar, 2019.

[13] Market purchases at costs above a gas combustion turbine were included in both DEC and DEP systems to provide enough capacity to meet demand. Market purchases were not permitted when enough capacity existed but intra-hour ramp rate constraints caused an LOLE$_{FLEX}$ violation. See Astrapé Solar Ancillary Service Study at 8-10.

are then charged the average SISC, while ratepayers pay for the integration of utility-owned solar. Under this methodology, ratepayers and solar QFs pay the same average cost for the integration of utility-owned and QF-owned solar.

If utility-owned solar had been included in the base case, that would result in a higher solar integration cost assigned to solar QFs than to utility-owned solar, because the incremental cost of integrating solar resources increases as solar penetration increases. If utility-owned solar had not been included in the calculation of the average service charge, the result would be higher integration costs assigned to utility-owned solar (and therefore ratepayers) than those assigned to solar QFs. I believe that the most equitable result is for the SISC to be the same for both QF and utility-owned solar.

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT THE VOLATILITY DATA USED IS REASONABLE?

A. The Public Staff's concerns regarding data volatility were primarily centered around the integration costs calculated for higher levels of solar penetration, such as 3,020 MW in DEC and 4,610 MW in DEP.[14] The Public Staff still has concerns about how volatility is modeled in these scenarios, as addressed in our initial comments.

[14] See Astrapé Solar Ancillary Service Study at 47-52.

However, the estimated integration costs associated with these high levels of solar penetration are only projections, and are not being used by Duke to assess any charges in this proceeding. As Duke continues to update their integration cost studies, new solar facilities are constructed and connected to the grid, and additional granular solar output data is collected, the Public Staff expects this issue to generally resolve itself. Duke acknowledges this, stating that they, "… do not dispute that use of more current solar volatility data can impact assumptions over time … for this reason, the Companies advocate for updating the historic volatility data biennially in future avoided costs proceedings…."[15]

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT THE FORCED SELECTION OF 'LOAD FOLLOWING UP RESERVES' IN THE ASTRAPÉ MODEL IS REASONABLE?

A. The Public Staff acknowledges that, as Duke identified in their reply comments,[16] Astrapé modeled several different types of ancillary services, such as quick start reserves, regulation requirement up and down, and load following up and down.[17] While only one type is increased to integrate solar (load following up), the number of different services modeled is more granular than several other

[15] Duke Reply Comments at 104.
[16] *Id.* at 113.
[17] *See* Astrapé Solar Ancillary Service Study, Table 18, at 43.

integration studies reviewed. While future improvements could be made to the model in order to better optimize the available ancillary services used to meet load as the penetration of renewables increases, it is reasonable for Duke to utilize the load following up reserves at this time.[18]

Q. WHY DOES THE PUBLIC STAFF BELIEVE THAT THE RELIABILITY STANDARDS ADHERED TO IN THE ASTRAPÉ MODEL ARE REASONABLE?

A. Duke and Astrapé provided information to the Public Staff that used post-processing techniques to estimate the impact of increasing the $\text{LOLE}_{\text{FLEX}}$ metric from 0.1 to both 0.3 and 1.0. Increasing the allowed frequency of events in which load could not be met due to ramping constraints by 10-fold (in the case of a 1.0 $\text{LOLE}_{\text{FLEX}}$) reduced the average Solar Integration Services Charge by 6.2% in DEC and 1.9% in DEP, due to a reduction in total load following capacity required. The additional analysis provided to the Public Staff is attached heretofore as Exhibit C.

The Public Staff's primary concern was that the change in the average SISC would be significant due to the increasing marginal

[18] Many of the various ancillary services offer similar capabilities and are often comprised of overlapping generation units (i.e., the same unit may be able to provide both 10-minute and 60-minute reserves). In addition, the integration cost studies from other states previously discussed generally only utilized one type of ancillary service.

cost of integrating intermittent resources. However, it appears that the loosening of the reliability standard does not have the significant effect that was anticipated by the Public Staff. In addition, the quantity of incremental load following reserves appears to be reasonable compared to the capacity of solar generation resources on the system. As a result of this further analysis, I believe that the substantive concerns the Public Staff had with the quantification of the SISC have been resolved without the need for revisions to the Astrapé study.

Q. OVERALL, DO YOU BELIEVE THAT DUKE HAS MADE A REASONABLE ATTEMPT TO QUANTIFY THE INCREASE IN SYSTEM COSTS DUE TO INTERMITTENT RESOURCES?

A. Yes, I believe that the methodology used to quantify the SISC is reasonable and that assessing this charge on solar QFs is appropriate. This position is supported in more detail by the Stipulation of Partial Settlement between DEC, DEP, and the Public Staff, filed May 21, 2019 ("SISC Stipulation").

II. <u>Duke's Proposed SISC "Average Cost" Rate Design and Biennial Update</u>

Q. PLEASE DESCRIBE HOW DUKE HAS PROPOSED TO ADMINISTER THE SISC.

A. Duke plans to apply the charge to all new solar facilities that establish a Legally Enforceable Obligation ("LEO") under the avoided cost rates filed in this proceeding, and to any solar facilities that seek to renew their expiring contracts. Thus, all QF solar facilities will eventually pay the SISC. Duke proposes to charge each solar facility the average integration cost based on the aggregate capacity of solar connected to the grid at the time they establish a LEO, as opposed to the incremental cost associated with a particular block of solar studied by Astrapé. For the SISC included in Schedule PP for DEC and DEP, this represents a charge of $1.10/MWh and $2.39/MWh, respectively, and would reflect the existing plus HB 589 transition ("Existing Plus Transition") solar capacity in DEP (2,950 MW) and DEC (840 MW),

Q. DOES DUKE PLAN TO UPDATE THE CHARGE PERIODICALLY?

A. Yes. Duke proposes to re-run its Astrapé study with updated inputs and levels of solar penetration in each biennial avoided cost proceeding. This recalculated SISC would then apply to all solar facilities subject to the charge; that is, the charge would be refreshed every two years.

Q. DO YOU HAVE ANY CONCERNS WITH THE UPDATE PROCESS?

A. Yes. Similar to the Public Staff's position in Sub 148, we have concerns with the uncertainty QFs would face with rates refreshing every two years.[19] In the Astrapé study, Duke calculated the average SISC for higher levels of solar penetration, indicating that the charge could reach as high as $9.75/MWh in DEC and $14.91/MWh in DEP.[20] While Duke has committed to performing this analysis in all future updates to the SISC "to reduce uncertainty,"[21] it does not consider the effect of natural gas price volatility. Fluctuations in the cost of natural gas could cause the projected SISC to be substantially different in future studies, because the majority of units providing regulation reserves are natural gas fired and the study only encompasses one year and does not project natural gas prices into the future. Thus, projecting the SISC at higher solar penetration levels does not address a significant source of uncertainty. The forecast of the higher SISC at higher levels of solar penetration and the additional uncertainty due to the impact of fluctuating natural gas prices may make it difficult to finance solar projects subject to the charge.

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[19] Public Staff Initial Comments at 37-39.

[20] *See* Astrapé Solar Ancillary Service Study, Table 20 (DEC) and Table 21 (DEP). These estimates reflect no reduction in solar volatility with the addition of 1,500 MW of solar capacity in addition to existing, transition, and CPRE Tranche 1 capacity.

[21] Duke Reply Comments at 121.

Q. DID THE PUBLIC STAFF PROPOSE ANY ALTERNATIVE OPTIONS FOR CONSIDERATION?

A. Yes. We recognize that integration costs can change over time, particularly if Duke's system characteristics or natural gas prices change significantly. As such, we proposed two possible options: (i) charge solar facilities the incremental SISC (which is higher than the average[22]) and eliminate the refresh; or (ii) charge solar facilities the average SISC, and allow a refresh, but implement a reasonable cap on the amount by which the SISC could change to provide certainty to QFs.

Q. HOW DOES THE SISC STIPULATION ADDRESS THIS ISSUE?

A. On May 21, 2019, the Public Staff and Duke filed a Stipulation of Partial Settlement Regarding the Solar Integration Services Charge ("SISC Stipulation"). Section VI of the SISC Stipulation applies a cap on potential future increases of the SISC, stating that the cap is "reasonable and appropriate to mitigate the risk for Sub 158 Vintage solar generators of currently-unquantifiable potential future increases" in the SISC. The cap is calculated by the Astrapé model to determine the incremental integration cost of the last 100 MW of

[22] The average SISC is calculated by dividing the total increase in system costs by the total amount of generation from all solar capacity added to the model. The incremental SISC is calculated by dividing the incremental increase in system costs by the total amount of generation, from the last "block" of incremental solar capacity added to the model.

solar expected to be interconnected by the end of the current Sub 158 biennial period (2020), using projections from DEC's and DEP's Integrated Resource Plans ("IRPs"). Under this methodology, the SISC would be capped for Sub 158 Vintage QFs at $3.22/MWh in DEC and $6.70/MWh in DEP.

Q. DOES A CAP ON THE SISC EXPOSE RATEPAYERS TO UNDUE RISK?

A. No. As stated in Duke witness Wheeler's testimony, the inclusion of a cap might result in some level of subsidization of QFs by general ratepayers if the average cost of integrating solar resources exceeds the cap.[23] However, the Public Staff believes that an important aspect of these proceedings is to ensure that the majority of costs imposed by intermittent solar QFs is recovered from intermittent solar QFs. The cap provides a reasonable balance between reducing uncertainty for QFs and refunding ratepayers for the costs of integrating intermittent QFs.

Q. DOES IMPOSING THE CAP WHILE ALLOWING THE REFRESH PROVIDE ANY BENEFITS TO RATEPAYERS OR QFs?

A. I believe so. As discussed in Section I of my testimony, several of the Public Staff's concerns with the Astrapé study, such as the load

[23] *See* Direct Testimony of Steven B. Wheeler at 7.

volatility data and the use of a variety of ancillary services, would be allayed with additional opportunities to improve the available data and the Astrapé model. For example, Duke may discover over the next several years that, due to the geographical diversity of new solar facilities, solar volatility is less than expected, resulting in a decreased SISC to the benefit of QFs. Future updates to the ancillary services study will improve the data and modeling used to determine the SISC, resulting in more accurate recovery of integration costs from QFs.

In addition, imposing the cap grants more certainty to QFs who are seeking interconnection to sell their energy and capacity at avoided cost rates. As the Commission summarized in its October 11, 2017, *Order Establishing Standard Rates and Contract Terms* in Docket No. E-100, Sub 148:

> [A] QF's legal right to long-term fixed rates under Section 210 of PURPA is addressed in FERC's J.D. Wind Orders. Order No. 69 establishes the appropriateness of a fixed QF contract price for energy and capacity at the outset of the QF's obligation because fixed prices are necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore, its financial feasibility before beginning the construction of a facility.[24]

[24] *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*, at 34, Docket No. E-100, Sub 148 (Oct. 11, 2017).

While the cap does not provide a single, fixed contract price for the duration of the PPA, it does provide the QF with reasonable certainty as to the maximum SISC charge it could be responsible for during the pendency of its obligation, limiting its potential exposure as it seeks financing.

III. DENC's Proposed Re-Dispatch Charge (RDC)

Q. WHAT IS DENC'S RDC?

A. DENC's RDC reflects the deviations from the optimal dispatch order of DENC's fleet of dispatchable generation units due to fluctuations in the output of intermittent, non-dispatchable resources. Similar to the changes in dispatch order caused by load uncertainty, the uncertainty of intermittent, non-dispatchable energy resources causes units to be dispatched out of the least cost dispatch order on an hour-to-hour basis, leading to increased fuel and purchased energy costs, which are passed on to ratepayers.

Q. HOW DOES DENC CALCULATE ITS RDC?

A. DENC utilizes a simulation analysis with a production cost model to determine the impact on total system costs under various levels of solar PV penetration, and calculates an average weighted re-dispatch cost over various scenarios and cost categories. DENC's analysis incorporates approximately 85 model runs and a differential analysis between the results of each run to isolate the increase in costs associated with solar output fluctuations from the increase in costs associated with load fluctuations – both of which cause the incurrence of re-dispatch costs, but only one of which should be assigned to intermittent QFs.

The result of each differential analysis is an RDC for that specific scenario. DENC then averaged the RDCs of each scenario, choosing to assign equal weight to each combination of solar penetration and cost inclusion scenarios,[25] ultimately arriving at a RDC of $1.78/MWh, which it proposes to apply to any intermittent QF that signs a contract under its Sub 158 tariff. Unlike the methodology Duke employs to calculate its SISC, the DENC method is not probabilistic and does not measure system reliability.

Q. IS THE PROPOSED RDC A REASONABLE ATTEMPT TO QUANTIFY THE COSTS INCURRED BY INTERMITTENT GENERATORS?

A. Generally, yes, although we have identified concerns with the weightings applied to the various scenarios. In our reply comments, we suggest an alternate set of weightings that result in an RDC of

[25] Solar penetration scenarios consist of total solar capacity of: 80 MW, 2,000 MW, and 4,000 MW. Cost inclusion scenarios consist of: “all costs”, “No PJM”, “No Pumped Storage”, and “generation costs only.”

$0.78/MWh, which we believe is more reflective of the DENC system and actual costs incurred. Further, including cost scenarios such as the "No PJM" scenario[26] would inappropriately exclude the benefits provided by solar QFs due to DENC's membership in PJM.

Q. DO THE INTERVENORS IN THIS CASE SUPPORT DENC'S RDC?

A. Generally, no, for the same reasons they oppose Duke's SISC. SACE witness Kirby identifies similar concerns with scenario weightings as those identified by the Public Staff.[27]

Q. DOES DENC ACCEPT THE PUBLIC STAFF'S PROPOSED REVISIONS TO ITS RDC?

A. Yes. While DENC maintains that the weightings it originally assigned to each solar penetration and cost inclusion scenario were appropriate, it is willing to recalculate the RDC with the recommended weightings the Public Staff proposed in its reply comments.[28]

Q. IS THERE ANY OVERLAP BETWEEN DENC'S RDC AND DUKE'S SISC?

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[26] The "No PJM" scenario reflects model runs in which DENC's system interacts with PJM, but the net revenue from market transactions is ignored.
[27] Initial Comments of SACE, Attachment C, at 1-2.
[28] *See* Reply Comments of the Public Staff at 21.

A. Yes. While the two charges attempt to quantify different aspects of integrating intermittent generation and use different approaches, both methods are based on the principle that increased costs are generally derived from higher fuel consumption due to each Utility's fleet operating outside of optimal ranges and out of optimal dispatch order. As such, there is likely some overlap in the increased costs the Utilities incur under the two approaches. Based on the review of the RDC and the SISC, I believe that the two charges are not mutually exclusive.

IV. <u>NCSEA and Public Staff's Proposals Related To Differing Ancillary Services Costs For Innovative QFs</u>

Q. AS IT RELATES TO ANCILLARY SERVICES, PLEASE DESCRIBE THE FINDINGS OF THE ASTRAPÉ STUDY.

A. The Astrapé model identified a need for additional ancillary services in order to respond to the intra-hour fluctuations of solar generation facilities interconnected to the grid.

Q. WHICH ANCILLARY SERVICES ARE IDENTIFIED BY THE MODEL?

A. As previously discussed, the Astrapé model used "load following up reserves," which are identified as a "60 minute product served by units who have minimum load less than maximum load,"[29] to meet the intra-hourly fluctuations of solar output. While the model identified other types of ancillary services, only load following up reserves were added as solar penetration levels increased.

Q. WHAT QUANTITY OF LOAD FOLLOWING UP RESERVES DID THE ASTRAPÉ STUDY IDENTIFY AS NECESSARY TO INTEGRATE SOLAR RESOURCES?

A. For DEC, 26 MW of additional load following up reserves were required to integrate a total of 840 MW of solar. For DEP, 166 MW of additional load following up reserves were required to integrate a total of 2,950 MW of solar. These solar capacity totals reflect the Existing Plus Transition solar capacity for each of the utilities.

Q. WHAT DO YOU MEAN BY 'ADDITIONAL' LOAD FOLLOWING UP RESERVES?

A. Astrapé performed a model run without any solar on the grid, and due to load fluctuations and generator outages, the model required a certain amount of "baseline" ancillary services to reliably meet demand. In subsequent model runs, as Astrapé increased the amount of solar penetration, the reliability of the grid (as measured by the $LOLE_{FLEX}$ metric) decreased. In order to keep grid reliability

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[29] Astrapé Ancillary Services Study at 43.

constant as additional intermittent solar is added, the amount of load following up reserves was increased. This increase represents the additional ancillary services that are attributable to the intermittency of solar generators on the grid.

It is the Public Staff's understanding that the Duke-owned generation fleet has sufficient available capacity currently to meet this additional ancillary services requirement, and that at this time there is no need for Duke to build additional generation facilities solely to provide this additional ancillary services requirement.

Q. DOES PURPA REQUIRE UTILITIES TO PURCHASE ANCILLARY SERVICES FROM QFs?

A. I am not a lawyer, but it is my understanding that PURPA generally requires a utility to purchase the energy and capacity output from a QF at the utility's avoided costs. PURPA does not, however, obligate the utility to purchase ancillary services from QFs.[30]

Q. COULD THE NEED FOR ANCILLARY SERVICES IDENTIFIED BY THE ASTRAPÉ MODEL BE SERVED BY THE IMPLEMENTATION OF AN ANCILLARY SERVICES MARKET IN NORTH CAROLINA?

[30] 18 CFR § 292.303(a), Electric Utility Obligations Under This Subpart.

A. Potentially, yes. In our reply comments, the Public Staff agreed with NCSEA witness Johnson's assertion that certain QFs have the technical ability to provide ancillary services, and we stated that, "a market or competitive solicitation for a limited quantity of ancillary services into which third party generators could bid has the potential to reduce costs to ratepayers and facilitate the cost-effective integration of intermittent resources."[31]

More importantly, the Astrapé study identified a methodology for Duke to quantify the "avoided cost" of ancillary services. This information could be useful in future proceedings and in negotiated contracts where technologically capable QFs might be compensated for ancillary services provided to the grid.

Q. ARE THERE ANY SPECIFIC CHALLENGES TO IMPLEMENTING A MARKET FOR ANCILLARY SERVICES IN NORTH CAROLINA?

A. Yes, there are several. First, Duke is not a member of an RTO, and as such, no organized competitive market for third-party services exists. In RTOs such as PJM, there is a specifically defined ancillary services market into which any generator may bid.

Second, as previously stated, PURPA does not require utilities to purchase ancillary services from QFs. With the responsibility for

[31] Reply Comments of the Public Staff at 23.

reliable grid operation falling on the utility, a market for such services would face significant regulatory challenges. For a QF to provide ancillary services for reliability, a responsibility borne solely by the utility, the utility may assert that it would need complete control over the QF's operations, raising complex questions of ownership and control in the traditional relationship between a utility and a QF under PURPA.

Finally, the additional ancillary services need identified by the Astrapé study is not large – a total of 192 MW in DEC and DEP combined to integrate the combined 3,790 MW of Existing Plus Transition solar. While this need will grow as solar penetration increases, the costs to conduct a competitive solicitation to procure this amount of ancillary services from third parties might exceed the savings actually realized.

Q. DOES THE PUBLIC STAFF AGREE WITH NCSEA THAT INNOVATIVE QFs MAY REDUCE THE NEED FOR ADDITIONAL ANCILLARY SERVICES IN A WAY THAT MAKES THE SISC UNNECESSARY?

A. Yes. The Public Staff believes that certain technologies, such as energy storage, could, if operated appropriately, reduce or eliminate the intermittency of the output from solar generators. To the extent a QF can materially demonstrate that it does not impose additional ancillary service costs on the system, it should not be subject to the SISC or, to a lesser extent, the RDC.

Q. DO QFS NOT ELIGIBLE FOR THE STANDARD OFFER HAVE THE ABILITY TO MITIGATE THE SISC?

A. Yes. Section II.A of the SISC Stipulation specifically grants a QF that enters into a negotiated contract the ability to mitigate the SISC by demonstrating and contractually obligating itself to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements.

V. <u>Duke's Proposed Modifications to the Standard Terms and Conditions as related to the Energy Storage Protocol</u>

Q. PLEASE BRIEFLY SUMMARIZE THE ENERGY STORAGE PROTOCOL PROPOSED FOR QFs SELLING UNDER SCHEDULE PP.

A. The energy storage protocol provides a standardized set of operating instructions to QFs utilizing energy storage devices that wish to sell power under Duke's Schedule PP. Broadly, it includes provisions: (i) mandating the storage device be charged exclusively from the renewable energy resource; (ii) limiting the maximum output of the facility; (iii) limiting the ramp rate for the storage device and the combined ramp rate for the entire facility; (iv) prescribing time windows, aligned with premium peak hours, during which the storage device can be discharged; (v) requiring that during discharge windows, the storage device discharge in such a way as to hold the total facility output constant; and (vi) permitting Duke the right to add or modify operating restrictions to the extent necessary to comply with NERC standards. The energy storage protocol for Schedule PP facilities is attached as Exhibit D.

Q. HOW DOES THE ENERGY STORAGE PROTOCOL PROPOSED IN THIS PROCEEDING DIFFER FROM THE ENERGY STORAGE PROTOCOL USED IN TRANCHE 1 OF THE COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY ("CPRE") PROGRAM?[32]

A. The terms of the energy storage protocol included as part of the Tranche 1 CPRE purchase power agreement ("PPA"), require the QF and Duke to communicate more frequently about the state of charge of the energy storage device and allowable bulk discharge windows for the QF. Duke's proposal in this proceeding has modified that communication requirement to require levelized total facility output during premium peak windows, reflecting that the Schedule

[32] Docket Nos. E-2, Sub 1159, and E-7, Sub 1156.

PP facilities will likely be smaller and more numerous than CPRE facilities.

In addition, the ramp rates have been modified. For example, the CPRE energy storage protocol restricted ramp rates for the storage resource to 5% of the facility's nameplate capacity per minute; in Schedule PP, the ramp rate for the storage resource is restricted to 10% of the storage resource's capacity per minute. As different facilities may have different energy storage to solar capacity ratios, it is difficult to determine if these changes constitute a more or less restrictive policy than that in the CPRE proceeding.[33] The energy storage protocol for Tranche 1 of the CPRE is attached as Exhibit E.

Q. DOES THE PUBLIC STAFF HAVE A POSITION AS TO WHETHER THE ENERGY STORAGE PROTOCOL PROPOSED FOR QFs SELLING UNDER SCHEDULE PP IS REASONABLE?

A. While the Public Staff does not have the expertise to determine whether or not the proposed energy storage protocol is reasonable, we recognize that some operational guidelines for facilities incorporating energy storage devices are appropriate to ensure that the facilities are operated in a safe, reliable, and efficient manner,

[33] In subsequent discovery (presented as Exhibit F), Duke has indicated that it chose the ramp rate constraints in an attempt to accommodate an industry standard of ramping to full output over a 10-minute period.

and that the criteria addressed in the Duke's proposed energy storage protocol are relevant factors in providing information to system operators on how the storage facilities would operate in parallel with the utilities system.

Due to the complexity of Duke's system and the need to consider the aggregate effect of potentially large quantities of third-party energy storage connected to the grid, we generally defer to Duke on how to best maintain system reliability. However, we understand that intervenors representing solar developers have raised concerns about the energy storage protocol, and support a technical conference or stakeholder proceeding to comprehensively address energy storage.

Q. WILL LARGER QFs NOT ELIGIBLE FOR SCHEDULE PP BE SUBJECT TO THE SAME ENERGY STORAGE PROTOCOL IN THE FUTURE?

A. At this time, Duke has only provided the energy storage protocol for facilities that commit to sell under its standard offer avoided cost tariffs. However, Section II.A of the SISC Stipulation specifically allows QFs that enter into negotiated contracts the ability to operate in a manner that reduces or eliminates the need for ancillary services, thereby reducing or waiving the SISC. It is likely that such operation would be substantially different than the manner of operation allowed pursuant to the energy storage protocol proposed in this proceeding.[34]

Therefore, I do not believe it is not appropriate to enforce the standard energy storage protocol on a solar QF that is attempting to avail itself of the provisions of Section II.A of the SISC Stipulation; rather, such facilities should be given an opportunity to modify the energy storage protocol in such a way to obligate the facility to operate in a manner that materially reduces or eliminates the need for additional ancillary service requirements.

Q. WILL QFs WITH STORAGE PARTICIPATING IN FUTURE TRANCHES OF THE CPRE BE SUBJECT TO THE SAME ENERGY STORAGE PROTOCOL?

A. It is not clear. The Independent Administrator has submitted a list of "Storage Products and Attributes."[35] Most of these features of energy storage would be prohibited if the energy storage protocol proposed for Schedule PP were applied to CPRE projects. Further,

[34] For example, a solar QF that wishes to use an energy storage device to smooth its output profile and eliminate any unplanned fluctuations could be eligible to waive the SISC. However, such operation might require the energy storage device to discharge periodically throughout the day to compensate for intermittent cloud cover, which would violate the requirement for levelized output during premium peak hours. Ramp rate constraints contemplated in the proposed energy storage protocol might also be too restrictive to allow the battery to fully smooth the output profile in response to cloud cover.

[35] *See* "IA Stakeholder's Meeting Report" filed March 15, 2019, in Docket Nos. E-2, Sub 1159, and E-7, Sub 1156, Attachment A.

as the CPRE PPAs have 20-year terms, there is some concern that requiring CPRE projects with storage to exclusively charge from the renewable energy facility could unnecessarily restrict the ability of a solar plus storage facility to provide tangible and quantifiable grid benefits in the future. The CPRE stakeholders could not reach consensus on other areas of importance related to storage,[36] and this issue will likely be the subject of further discussion for future CPRE Tranches.

Q. DOES THE PUBLIC STAFF HAVE ANY SPECIFIC RECOMMENDATIONS FOR MODIFICATIONS TO THE ENERGY STORAGE PROTOCOL PROPOSED IN THIS PROCEEDING?

A. No. The Public Staff anticipates that other intervenors may submit specific concerns and proposed modifications to the energy storage protocol in their testimony, and will review and consider them as appropriate.

The Public Staff acknowledges that several stakeholders in the CPRE dockets have expressed concerns about the restrictions in the energy storage protocol. Although the protocol has been updated in this proceeding, we still anticipate that solar developers will see the proposed protocol as barrier to solar plus storage facilities. The

[36] *Id*. at 6-7.

Public Staff would like the concerns of the development community addressed in this Docket by both the Utilities and those intervenors who have experience operating renewable energy facilities coupled with energy storage. The Public Staff anticipates that, depending on the service the storage is providing, it may be appropriate to develop multiple protocols to address different services.[37]

VI. The Stipulation Filed April 18, 2019, Related To Energy And Capacity Rate Design ("Rate Design Stipulation").

Q. HOW DID THE PUBLIC STAFF AND DUKE REACH THE AGREEMENTS OUTLINED IN THE STIPULATION?

A. In its initial comments, the Public Staff requested additional granularity in the energy rate design beyond that proposed by Duke and DENC in their initial filings, and solicited feedback from intervenors and the Utilities on possible refinements. The Rate Design Stipulation represents the significant collaborative effort that went into reaching a compromise that met the Public Staff's basic core objective that, "to the extent possible, avoided energy costs should reflect each utility's actual avoided production cost."[38]

[37] Examples of potential energy storage services are presented in the "IA Responses to Technical Session Questions", filed May 31, 2019 in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156.
[38] Initial Comments of the Public Staff at 54.

The Public Staff believes the objective methodology presented as Attachment B of the Rate Design Stipulation will promote a more consistent approach to compensating solar facilities during the hours when energy is most needed in this proceeding and future biennial avoided cost proceedings.

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN THE RATE DESIGN STIPULATION AND DUKE'S ORIGINAL PROPOSED RATE DESIGN.

A. Broadly, the Rate Design Stipulation and Duke's original proposal both present similar improvements to the granularity of the on- and off-peak hours found in Duke's Option A and Option B rate designs approved in Sub 148. Both propose using load data to determine on- and off-peak energy hours, and both use Loss of Load Expectation ("LOLE") data based on the Astrapé Capacity Value of Solar study presented in Duke's 2018 IRPs[39] to determine capacity hours.

The Rate Design Stipulation largely incorporates the Public Staff's suggested additional granularity in energy hours. Specifically, the proposed rate design adds a shoulder season in a shift towards a three-season classification system; it also includes a "premium peak"

[39] 2018 Integrated Resource Plan and 2018 REPS Compliance Plan, filed by DEC and DEP in Docket No. E-100 Sub 157. (September 5, 2018).

designation, with energy rates higher than on-peak rates, for a limited number of hours where Duke's average marginal cost is in an upper percentile. Finally, it adopts a series of guidelines that should help Duke more objectively determine the appropriate rate design and seasonal classification of months in future avoided cost proceedings.

The Rate Design Stipulation is the result of significant give and take between Duke and the Public Staff, as both parties sought to balance the more administratively complex rate design proposed in the Public Staff's initial comments with the anticipated benefits to ratepayers from additional granularity.[40]

Q. DID THE PUBLIC STAFF SUGGEST ANY CHANGES TO THE RATE DESIGN FOR CAPACITY PAYMENTS?

A. The Public Staff largely agreed with Duke's proposed capacity payment hours and seasonal allocation for the reasons discussed in our initial comments,[41] and did not propose any significant changes to the capacity rate design. We believe that to prevent overpayment to QFs for capacity that is not needed, it is most appropriate to pay capacity payments only during hours where there is a loss of load risk.[42] As Duke's IRPs reflect winter planning, utility-owned capacity

[40] A more detailed discussion of the adjustments made by Duke and the Public Staff can be found in Duke Reply Comments at 70-73.

[41] Initial Comments of the Public Staff at 57.

[42] Loss of load risk was calculated on an hourly and monthly basis by Astrapé in its Capacity Value of Solar Study, filed in Docket No. E-100, Sub 157.

is only deferred when QFs can provide capacity during the winter hours when capacity is needed the most – specifically, the early morning hours.

The proposed use of the LOLE metric to determine the hours and seasons in which capacity is most needed is reasonable and protects ratepayers from overpaying for QF capacity. In addition, the proposed capacity rate design sends the appropriate price signals to QFs, providing price incentives to developers who design their facility to provide capacity when it is most valuable to the utility.

Q. WHY DO YOU BELIEVE THE RATE DESIGN STIPULATION IS IN THE BEST INTERESTS OF RATEPAYERS?

A. Generally, more granular avoided energy and capacity rates will send more accurate price signals to QFs. If there is enough of a differential between pricing in high value hours and low value hours (i.e., premium peak vs. off-peak hours), this differential may lead to developers investing in technology and energy generation facilities that best meet the needs of the electric grid.

The Public Staff believes the Rate Design Stipulation offers a rate design which pays QFs the highest rate for energy put on the grid when it is needed the most (such as early morning winter hours), and thus can bring ratepayers' and private developers' interests into alignment. This Rate Design Stipulation would provide innovative QFs with a rate design granular enough so that they can identify the periods of system need and be properly compensated for contributing to meet that need.

Q. HAS THE PUBLIC STAFF INVESTIGATED THE POTENTIAL IMPACT OF THE RATE DESIGN STIPULATION ON RATEPAYERS?

A. Yes. An analysis of the original Sub 158 rates filed by Duke on November 1, 2018, and the proposed Rate Design Stipulation rates is presented below in Figure 1.

A comparison of the impact of as-filed rates and the Stipulation rates (hatched yellow bars) on the expected revenue[43] for a solar-only facility shows that the proposed changes in the Stipulation are effectively revenue-neutral; that is, a solar-only facility would be expected to earn approximately the same revenue under the original Sub 158 rate design proposed by Duke as it would under the rate design in the Rate Design Stipulation.[44] This “revenue neutrality” was an important element for the Public Staff, as the Public Staff did not want to propose changes that would provide additional

[43] The effect of a solar integration services charge is not included in this analysis.

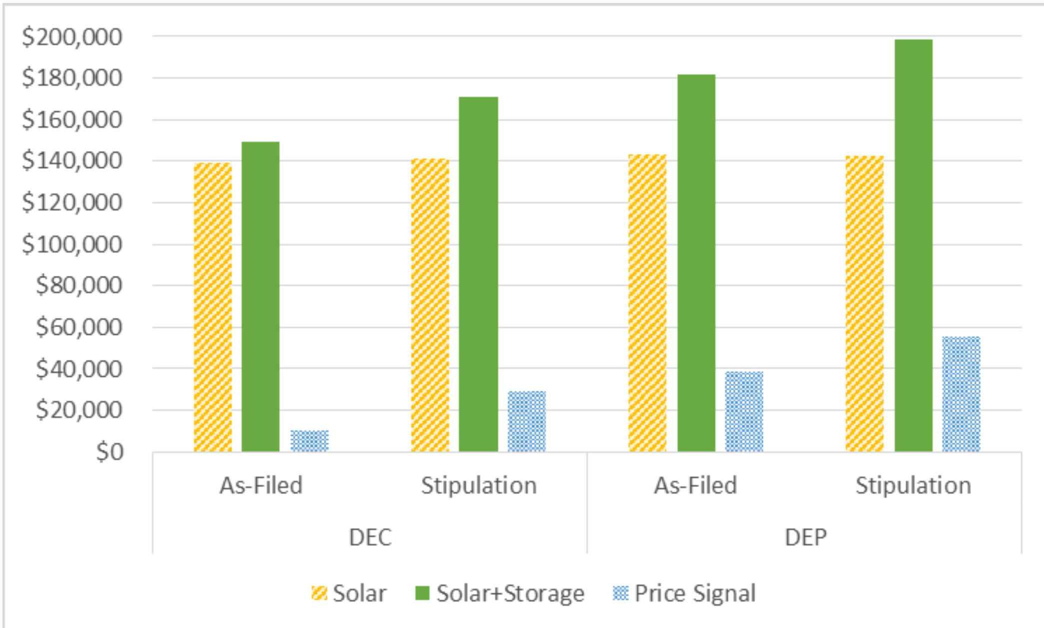
[44] Adopting the Stipulation rate design would increase payments to a DEC solar-only facility by 1.7%, and decrease payments to a DEP solar-only facility by 0.4%.

compensation to a solar-only QF that did not modify its output to meet the needs of the grid.

An estimate of the revenue that could be expected for a solar plus storage facility under the as-filed rates and the Stipulation rates is shown by the solid green bars of Figure 1. The difference between the solar and the solar plus storage revenue under the same rate design can be thought of as the "price signal" for the addition of storage[45] (displayed as a dotted blue bar) – it represents the increase in revenue that could be expected if a battery were added to the facility and dispatched in an optimal manner. By providing more granular rates that closely align with the actual avoided costs of the utility, the Stipulation has the effect of increasing this price signal by 185% in DEC and 45% in DEP.

[45] While the Public Staff discusses energy storage in this example, there are other modifications that could be made to a solar facility to better align with more granular energy rates, such as east or west facing panels, single or dual axis tracking, increased inverter loading ratio through over-paneling the facility, etc.

Figure 1: Comparison of first-year revenue for a 2 MW_{AC} solar QF without and with 1 MW/4MWh of battery storage. The "Price Signal" bar refers to the modeled increase in revenue associated with the addition and optimal operation of the battery storage device. Revenue includes energy and capacity payments.



In summary, compared to Duke's original proposed rate design, the Rate Design Stipulation provides rates that are revenue neutral to QFs that do not design their facilities to meet the more granular price signals, and provides stronger price incentives to QFs that produce more energy in the premium peak hours. It better aligns the utility's true avoided costs with the rates paid to QFs under PURPA, and restricts capacity payments to QFs only in hours where there is a loss of load risk, incentivizing QFs to provide capacity and energy at times when the system needs are greatest.

The Public Staff also believes that the methodology utilized to reach the Rate Design Stipulation could help streamline future avoided cost proceedings by simplifying the energy and capacity rate designs proposed by the Utilities.

Q. HAS THE PUBLIC STAFF ENGAGED DENC OR OTHER INTERVENORS IN ITS DISCUSSION OF RATE DESIGN?

A. Yes. The Public Staff and DENC discussed similar modifications to its avoided cost rate design. DENC and the Public Staff have largely reached agreement on the details of a proposed rate design, and DENC indicated in its reply comments that it would be willing to accept the Public Staff's proposal, with certain modifications.[46] The Public Staff agrees with DENC's proposed modifications, which include: (i) the inclusion of September as a summer month; and (ii) the expansion of the premium peak hours to encompass four hours in the summer and four hours in the winter (two in the morning and two in the evening). The Public Staff notes that as modified, our proposal for DENC is nearly identical to the Duke Stipulation; however, we support the consideration of unique characteristics for individual Utilities in rate design.

In addition, the Public Staff reached out to NCSEA and NCCEBA to discuss the more granular rate design proposed in our initial comments. Although NCSEA and SACE generally supported the

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[46] Reply Comments of DENC at 23-24.

concept of more granular rates in their reply comments, they declined to become parties to the Stipulation.

Q. ARE THERE ANY CHANGES TO COMMISSION RULES THAT WOULD AID IN ACCOMMODATING THE RATE DESIGN STIPULATION?

A. Yes. The avoided cost rate design proposed in the Rate Design Stipulation recommends changes to the on-peak and off-peak hours, adopts new "premium peak" hours, and presents guidelines for evaluating energy hours and seasons in future avoided cost proceedings that could result in gradual changes of premium peak, on-peak, and off-peak hours over time. Therefore, the Public Staff believes that it is appropriate for the Commission to consider two minor changes to Commission Rules R8-64 for applications for a Certificate of Public Convenience and Necessity ("CPCN") and R8-71 for the expedited review of CPCN applications for utility-owned projects selected by the CPRE Program.

Q. PLEASE DESCRIBE THE RELEVANT PARTS OF THE CURRENT RULES FOR WHICH YOU ARE REQUESTING MODIFICATIONS.

A. Commission Rule R8-64(b)(6)(iii)(a) requires, in part, that CPCN applications for solar PV facilities entering into a contract of five years or more and of a size greater than 25 MW include "[a] detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year."

For utility-owned renewable projects that successfully bid into the CPRE program, R8-71(k)(2)(iii)(6) similarly requires the "projected annual production of the renewable energy facility in kilowatt-hours, including a detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year."

Q. PLEASE DESCRIBE THE CHANGES YOU ARE REQUESTING.

A. The Public Staff suggests that these requirements be streamlined to request an hourly production profile from the applicant for one year, whether it be a QF or a utility-owned facility. The information requested in the existing rules originates from hourly production profile data created by readily available solar PV modeling software, but the data requires additional processing to meet the existing rules' requirements. Thus, our proposed change should reduce the administrative burden on applicants by eliminating the additional processing. In addition, the Public Staff believes that its review of CPCN applications would benefit from an understanding of the production profile and factors which influence its shape, rather than simply monthly summaries.

A proposed revision to the rules is presented in Exhibit G.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit A

Jeffrey T. Thomas

I graduated from the University of Illinois Champaign-Urbana in 2009, earning a Bachelor of Science Degree in General Engineering. Afterwards, I worked in various operations management roles for General Electric, United Technologies Corporation, and Danaher Corporation. Originally a manufacturing and process engineer in GE's Operations Management and Leadership program, I eventually became a production supervisor, where I was responsible for the safety and productivity of a team of employees. I left manufacturing in 2015 to attend North Carolina State University, earning a Master of Science degree in Environmental Engineering. At NC State, I performed cost benefit analysis research on smart grid components at the Future Renewable Energy Electricity Delivery and Management Systems Engineering Research Center. My master's thesis focused on electric power system modeling, capacity expansion planning, linear programming techniques, and the effect of various state and national energy policies on North Carolina's generation portfolio and electricity costs. After obtaining my degree, I joined the Public Staff in November 2017. In my current role, I have filed testimony in CPCN proceedings, and have been involved in the implementation of HB 589 programs, utility cost recovery, renewable energy program management, customer complaints, and other aspects of utility regulation.

Utility	Study Year	Resource	Modeled as Island? [1]	Model Time Steps (min)	System Size (MW)	Intermittent Capacity (MW)	Intermittent Penetration (%)	Integration Charge ($/MWh)	Link
DEC	2018	Solar	Yes	5	18,136	840	5%	$1.10	
					18,136	1520	8%	$1.37	
DEP	2018	Solar	Yes	5	14,011	2950	21%	$2.39	
					14,011	3110	22%	$2.64	
Idaho Power	2016	Solar	Yes [3]	5	5,475	400	7%	$0.27	
					5,475	800	15%	$0.57	http://www.puc.idaho gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTE
					5,475	1200	22%	$0.69	GRATION%20STUDY%20REPORT.PDF
					5,475	1600	29%	$0.85	
Idaho Power	2013	Wind	Yes	5	3,245	800	25%	$8.06	http://www.puc.idaho gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTE
					3,245	1000	31%	$13.03	GRATION%20STUDY%20REPORT.PDF
					3,245	1200	37%	$19.01	
South Carolina Electric & Gas Company	2019	Solar	Yes	5	5,000	336	7%	$3.52	South Carolina PUC Docket No. 2019-2-E
					5,000	637	13%	$4.04	Direct Testimony of Matthew W. Tanner
					5,000	1044	21%	$3.96	Filed February 8, 2019
Arizona Public Service	2012	Solar	Yes	10	9,283	1038	11%	$1.62	https://www.esig.energy/resources/aps-solar-photovoltaic-pv-integration-cost-study/
					13,007	1669	13%	$2.67	
Public Service Company of Colorado	2016	Solar	Unclear	60	7,000	1000	14%	$0.01	https://www.xcelenergy com/staticfiles/xe/PDF/Attachment%20KLS-1.pdf
					7,000	1800	26%	$0.41	
Public Service Company of Colorado	2013	Solar	Unclear	60	7,000	117	2%	$0.50	http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and
					7,000	117	2%	$1.80	%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20S
					7,000	117	2%	$4.40	ervice%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf
Public Service Company of Colorado	2011	Wind	Unclear	60	7,035	1414	20%	$2.39	https://www.xcelenergy com/staticfiles/xe/Regulatory/Regulatory%20PDFs/11M-
					7,035	1939	28%	$3.40	710E_2G-3GReport_Final.pdf
					7,035	2999	43%	$4.02	

Notes

[1] Modeling as an "island" may still allow purchases to meet capacity shortfalls; but if the system cannot rely on outside market purchases to compensate for intermittent generation shortfalls, it is considered an "island".
[2] Shaded cells represent total ancillary reserves, not incrementa
[3] This study looked at the possible effect of an Energy Imbalance Market as a sensitivity

LOLE FLEX Starting Point/Benchmarking

2015 Historical Data shows average 60 minute load following supplied to be 1,663.0 MW (See Duke Load Following Calcs - 2015 for Staff.xls) versus 1,600.0 MW as the starting point in the Astrape modeled results. Astrape believes the 0.1 is more supportive of historical operations

Ancillary Service Costs for Existing Plus Transition maintaining different LOLE Flex values (.1, .3, and 1)

DEC		Base Case .1 LOLE Flex	Post Processing - Estimated .3 LOLE Flex	Post Processing - Estimated 1 LOLE Flex
Starting Spin/Load Following Supplied	MW	1,005	965	959
Average Ancillary Service Costs (Existing Plus Transition)	$/MWh	1.10	1.06	1.03
Existing Plus Transition - incremental load following	MW	26.24	26.00	25.95

DEP		Base Case .1 LOLE Flex	Post Processing - Estimated .3 LOLE Flex	Post Processing - Estimated 1 LOLE Flex
Starting Spin/Load Following Supplied	MW	594	579	575
Average Ancillary Service Costs (Existing Plus Transition)	$/MWh	2.39	2.35	2.35
Existing Plus Transition - incremental load following	MW	165.84	151.30	146.60

Exhibit D

CPRE PPA (6/8/18)
Energy Storage Protocol

1. The Storage Resource must be on the DC side of the inverter and charged exclusively by the Facility.

2. The Storage Resource will be controlled by the Seller, within operational limitations described below.

3. The maximum output of the Facility, including any storage capability, at any given time shall be limited to the Facility's maximum Nameplate Capacity Rating (AC) as specified in the Agreement.

4. The Seller may not increase the Facility's Capacity, including any DC Nameplate Capacity Rating (MW) or AC Nameplate Capacity Rating (MW) or Storage Resource capacity (MW/MWh) beyond what is specified in the Agreement.

5. The discharge of stored energy is not permitted while the Facility has received or is subject to a Dispatch Down instruction or control signal from the System Operator.

6. Ramp rates for Storage Resource shall not exceed 5 percent of the Facility's Nameplate Capacity Rating on a per minute basis, whether up or down, at any time that the Facility is not generating.

7. When the Facility is generating, the Storage Resource shall not act to increase the net ramp rate of the Facility by more than 1 percent of the Facility's Nameplate Capacity Rating per minute in relation to the output from the Facility alone, over a one minute interval, up or down.

8. Scheduling and other storage limitations:
    a. Seller shall, by 8am each day, provide a day-ahead forecast of planned initial state of energy storage (MWh) and planned charging (MWh) of storage for each hour.
    b. By 4pm each day, Buyer will make commercially reasonable efforts to provide Seller with a window for bulk discharge with start and end times for the following day, including off-peak days.
        i. Outside of the bulk discharge window, discharge of the Storage Resource will not be permitted until the Storage Resource reaches and remains at a state of charge of at least 70% of the Allowable Depth of Discharge (as defined below).

ii. During on-peak days, the bulk discharge window will be entirely contained within the respective on-peak hours.
iii. Buyer will make commercially reasonable efforts to provide a minimum of 3 hours to discharge remaining battery capacity within each on-peak period.
iv. The discharge rate (in MW) shall be levelized across the bulk discharge window except as limited by ramp rate criteria or inverter capability.
v. For non-summer periods, if the bulk discharge window is not long enough to empty the battery before solar generation is expected to be at full output, the bulk discharge window may be moved up to allow full storage discharge within the on-peak window.

c. The storage charging (Active Power) when the Storage Resource is not inverter limited, shall be limited to 30% of a Facility's storage Allowable Depth of Discharge (e.g., a 10MWh battery with an Allowable Depth of Discharge of 8MWh could charge Active Power at a maximum of 2.4MW).

9. Buyer reserves the right to add or modify operating restrictions specified in these Energy Storage Protocols to the extent necessary to comply with NERC Standards as such standards may be modified from time to time during the Term. Any such modification shall be implemented by Buyer in a Commercially Reasonable Manner and shall be applied to the Facility and Buyer's own generating assets on a non-discriminatory basis. If Seller can make a Commercially Reasonable Demonstration to Buyer, which is approved by Buyer in its reasonable discretion that the Facility does not contribute to potential NERC compliance violations for which the modifications have been implemented, then such modifications shall not apply to the Facility.

10. Seller will only be compensated for Energy and Capacity actually provided to Buyer in accordance with the terms of the Agreement.

Notes:

a) For facilities equipped with energy storage devices, Seller shall be required to provide the "Nameplate Capacity Ratings" for the Facility in both AC and DC and include in Exhibit 4.
b) The storage device capacity (MW and MWh) shall be specified in Exhibit 4.

Definitions:

"Allowable Depth of Discharge" shall mean the MWh energy storage potential, considering the original equipment manufacturer's recommendations and any emergent operating limitations, at a given point in time.
Other capitalized terms used in this Exhibit which have not been defined herein shall have the meaning ascribed to such terms in the Agreement to which this exhibit is attached.

Exhibit E

Schedule PP PPA
Energy Storage Protocol

1. The Storage Resource must be on the DC side of the inverter and charged exclusively by the Facility.

2. The Storage Resource will be controlled by the Seller, within operational limitations described below.

3. The maximum output of the Facility, including any storage capability, at any given time shall be limited to the Facility's Contract Capacity as specified in the Agreement.

4. The discharge of stored energy is not permitted while the Facility has received or is subject to a curtailment instruction (i.e., System Operator Instruction) from the system operator.

5. Ramp rates for Storage Resource shall not exceed 10 percent of the Storage Resource's capacity (MW) on a per minute basis, whether up or down, at any time that the Facility is not generating, unless the system operator has waived this ramping limitation.

6. When the Facility is generating, the Storage Resource shall not act to increase the net ramp rate of the Facility by more than 5 percent of the Storage Resource's capacity (MW) per minute in relation to the output from the Facility alone, over a one-minute interval, up or down, unless the system operator has waived this ramping limitation.

7. Scheduling and other storage limitations:
   a. For all months/days with Premium Peak (as defined in the Proposed Settlement) windows, the Seller shall distribute any discharge of the storage device in a manner that levelizes (holds constant) the combined output of solar and storage at the highest practical level during the Premium Peak hours of such calendar day, except as limited by ramp rate criteria and inverter capability.
      i. For any storage discharge occurring on weekends and holidays where only Off-Peak energy rates apply, the Seller shall apply the same discharge logic that is applied to Weekdays/non-Holidays, for the respective month.
      ii. If the storage device is AC (MW) limited, discharge may begin prior to the Premium Peak window to allow the storage device to reach its Allowable Depth (as defined below) of Discharge.

b. For the remaining months without Premium Peak windows, the Seller shall distribute any discharge of the storage device in a way that levelizes (holds constant) the combined output of solar and storage at the highest practical level during three consecutive hours beginning with the hour of sunset.
    i. If the storage device is AC (MW) limited, discharge may continue beyond the three-hour window until the storage device reaches its Allowable Depth of Discharge.

8. Company reserves the right to add or modify operating restrictions specified in these Energy Storage Protocols to the extent necessary to comply with NERC Standards as such standards may be modified from time to time during the Term. Any such modification shall be implemented by Company in a Commercially Reasonable Manner and shall be applied to the Facility and Company's own generating assets on a non-discriminatory basis. If Seller can make a commercially reasonable demonstration to Company, which is approved by Company in its reasonable discretion that the Facility does not contribute to potential NERC compliance violations for which the modifications have been implemented; then such modifications shall not apply to the Facility.

9. Seller will only be compensated for Energy and Capacity actually provided to Buyer in accordance with the terms of the Agreement.

Notes:
a) "Allowable Depth of Discharge" shall mean the MWh energy storage potential, considering the original equipment manufacturer's recommendations and any emergent operating limitations, at a given point in time.
b) Other capitalized terms used in this Exhibit which have not been defined herein shall have the meaning ascribed to such terms in the Agreement to which this exhibit is attached.
c) Terms above assume conditions ascribed in the current Proposed Rate Design Settlement as of March 14th, 2019 (the "Proposed Settlement").

Exhibit F

NC Public Staff
Docket No. E-100, Sub 158
2018 Avoided Cost Rates
Joint Data Request No. 14
Item No. 14-15
Page 1 of 1

DUKE ENERGY PROGRESS, LLC and DUKE ENERGY CAROLINAS, LLC

Request:

Please describe the rationale for choosing the specific ramp rate constraint percentages of 5% of Facility's Nameplate Capacity (for CPRE) and 10% of Storage Resource Capacity (for Schedule PP).

Response:

When evaluating ramp limits for Tranche 1 of CPRE, the Companies decided to limit the ramp in a manner consistent with industry standard limits for ramping in power market purchase schedules. The current industry standard is a 10% ramp for a schedule from start to full schedule quantity (over a 10-minute period). Similarly, with Tranche 1, the Companies determined that a 5% limit on ramp of the solar facility ("Facility") would be approximate to a 10% ramp of a storage resource. The Companies' initial assumption was that a bid with a Facility might add a storage resource that was equal to 25% to 50% of the Facility capacity. For example, an 80 MW Facility would add a 20 MW or 40 MW storage resource. In this example, if the 40 MW storage resource was added, then the ramp rate limit of 5% of Facility would provide for 4 MW/Minute of ramp. This would allow the storage resource to discharge the full capacity (40 MW) in 10 minutes.

When evaluating the storage protocols for E-100 Sub 158, it was decided to tie the ramp directly to the storage resource that would be charging/discharging in keeping with efforts to streamline the Schedule PP Storage Protocols language. Therefore, it was decided to use a ramp limit of 10% of the storage resource.

Exhibit G

Proposed revision to Commission Rule R8-64(b)(6)(iii):

The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits ~~A detailed explanation of the anticipated kilowatt and kilowatthour outputs, on-peak and off-peak, for each month of the year. The explanation shall include a statement of the specific on peak and off peak hours underlying the applicant's quantification of anticipated kilowatt and kilowatt hour outputs~~;

Proposed revision to Commission Rule R8-71(k)(2)(iii)(6):

The projected annual hourly production profile for the first full year of operation of the renewable energy facility in kilowatt-hours, including an explanation of potential factors influencing the shape of the production profile, including fixed tilt or tracking panel arrays, inverter loading ratio, over-paneling, clipped energy, or inverter AC output power limits ~~including a detailed explanation of the anticipated kilowatt and kilowatt hour outputs, on peak and off peak, for each month of the year~~; and